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V. 2 of 2

WORK-PAPERS & RESPONSES TO COMMENTS FOR: FINAL REPORT ON THE FEASIBILITY OF ELECTRIC SYSTEM MUNICIPALIZATION IN SAN FRANCISCO -- TRANSMITTED BY SF/PUC RESOLUTION NO. 97-0048

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WORK-PAPERS & RESPONSES TO COMMENTS FOR: FINAL REPORT ON THE FEASIBILITY OF ELECTRIC SYSTEM MUNICIPALIZATION IN SAN FRANCISCO – TRANSMITTED BY SF/PUC RESOLUTION NO. 97-0048

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Workpapers

Chapter 1

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Muni/IOU Comparisons

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Workpaper 1.A

Survey of Muni and IOU Electric Rates

These workpapers present data that supports section A of Chapter 1. We have also prepared workpapers with details of various rate calculations. Table A-1 displays data for the California muni and IOU electric utilities on: generation plant investment, total dollars and normalized ($/kW); average rates (cents/kWhr); per-customer energy use (kWhr/year); distribution plant investment, total dollars and normalized ($/customer); numbers of employees; and energy purchases (kWhr/year and as a % of total electricity sales) and the sellers. Perhaps the most salient feature of these comparisons is that the normalized generation investment figures span a much wider range ($20 - $2074 per kW for the larger municipal electric systems, or more than 10,000% of the low-end figure) than do those for distribution ($1,012 - $2,335 per customer for the large systems, or 130% of the lower figure); the generation range reflects the fact that some utilities serve their loads mainly with purchase power and others do it mainly with their own generation, and the distribution figures show that all own their own local networks.

We will discuss the rate figures on succeeding pages, with graphical display by customer class. The annual use-per-customer figures demonstrate that Central Valley (SMUD) peak loads per customer greatly exceed those of coastal areas (SF), while the Central Valley load factors are much lower. Energy purchase percentages show comparability for all the state's major municipal systems, except LADWP, in being dependent on purchases for well over half of their requirements; LADWP purchases just under half of its energy, while all other California munis (except CCSF Hetch Hetchy, which is not a muni electric utility, even though it is included in this list) buy at least 70% of theirs.

UTILITY	GENERATION INVESTMENT	GENERATION PER KW	AVG. RATES CENTS/KWHR	USE KWHR/YR	DISTRIBUTION INVESTMENT	DISTRIBUTION PER CUSTOMER	NUMBER OF EMPLOYEES	KWHR PURCHASED	PURCHASES PCT OF SALES	POWER PURCHASED FROM
PACIFIC GAS AND ELECTRIC CO	10,859,165,424	725.40	12.25	6,422	8,373,545,004	1,926	15,544	25,958,509,000	36.30%	
SAN DIEGO GAS & ELECTRIC CO.	1,501,771,000	621.59	11.03	5,640	1,927,162,000	1,692	2,987	9,419,805,000	58.48%	
SOUTHERN CALIFORNIA EDISON CO	8,397,937,000	529.66	12.31	6,259	6,081,177,000	1,465	18,531	31,106,792,000	39.89%	
TOTAL	20,758,873,424	624.49			16,381,884,004	5,083	37,062	66,505,106,000	40.15%	

MUNICIPAL	GENERATION INVESTMENT	GENERATION PER KW	AVG. RATES CENTS/KWHR	USE KWHR/YR	DISTRIBUTION INVESTMENT	NUMBER OF EMPLOYEES	KWHR PURCHASED	PURCHASES PCT OF SALES	POWER PURCHASED FROM
LOS ANGELES DEPT OF WATER & POWER	2,230,249,000	301.63	9.95	5,759	2,794,202,000	2,084	10500	3,844,018,816	17.70%	AEPCO, ANAHEIM, AFS, BPA, BURBANK, DESERET, MPC, PASAD
SACRAMENTO MUNICIPAL UTILITY DISTRICT	356,647,000	395.13	8.11	8,732	687,154,000	1,452		7,877,380,000	93.12%	
ANAHEIM PUBLIC UTILITIES DEPT	280,463,000	1,778.61	9.44	5,735	152,197,000	1,470		2,431,453,862	82.62%	INTERMOUNTAIN POWER AGENCY, HOOVER AND S CAL ED; NON-F
SANTA CLARA ELECTRIC DEPT			7.20	5,333				2,225,508,700	102.29%	PACIFIC G&E, WAPA, NCPA, PORTLAND GE, CCPA WD I, BPA
RIVERSIDE UTILITIES DEPT	78,822,226	2,074.27	10.70	6,475	89,698,633	1,012		1,794,222,000	114.77%	
HETCH HETCHY WATER & POWER	94,085,136	241.55			78,100,625			482,999,313	33.81%	PACIFIC GAS & ELECTRIC CO AND OTHER MEMBERS OF THE WSP
PASADENA WATER AND POWER DEPT	56,303,373	274.65	9.30	5,321	134,659,449	2,335		963,856,000	86.29%	
PALO ALTO ELECTRIC UTILITY			5.50	6,385				1,080,124,017	102.54%	WAPA & NCPA
VERNON MUNICIPAL LIGHT DEPT			3.20	4,429				987,547,000	95.92%	SO CAL EDISON, CAL DEPT OF WATER RESOURCES, WAPA, LAD
GLENDALE PUBLIC SERVICE DEPT			9.30	4,720				906,919,000	91.04%	LADWP, BPA, IDAHO PWR, MONTANT PWR, PGE, WASH WATER PW
BURBANK PUBLIC SERVICE DEPT	6,960,760	20.09	9.49	5,176				836,665,000	87.30%	BPA, BC HYDRO, HOOVER DAM HYDRO, IDAHO PWR, LADWP, MON
REDDING ELECTRIC DEPT			6.79	10,814				721,849,000	104.73%	WAPA & PG&E
ROSEVILLE ELECTRIC DEPT.			7.50	9,000				601,693,134	103.71%	WAPA & NCPA
ALAMEDA BUREAU OF ELECTRICITY			10.88	4,648	36,648,558	1,168		512,880,031	103.41%	WAPA & NORTHERN CAL PWR AGENCY
LODI MUNICIPAL ELECTRIC SYSTEM			10.57	6,543				379,887,000	104.97%	N CAL PWR AGENCY & WAPA
COLTON ELECTRIC UTILITY DEPT.			8.04	5,140				141,117,039	67.78%	SOUTHERN CALIFORNIA EDISON, PALO VERDE, HOOVER, IDAHO
AZUSA LIGHT & WATER DEPT.			8.45	5,095				200,798,000	107.56%	SOUTHERN CALIFORNIA EDISON CO., CITY OF PASADENA, MSPP
LOMPOC UTILITY SERVICES/ELECTRICAL			8.95	4,127	18,765,542	1,314		127,551,800	108.32%	WAPA & NORTHERN CAL PWR AGENCY
BANNING ELECTRIC DEPT.			9.33	5,424				106,457,461	100.00%	SOUTHERN CALIFORNIA EDISON, SALT RIVER, LA DEPT. OF WA
URBAN MUNIC ELECTRIC SYSTEM	25,000,000	7,142.86	11.00	6,629	2,300,000	326		66,250,351	45.79%	DOE & WASHINGTON WATER & PWR
HEALDSBURG MUNIC ELECTRIC DEPT.			11.76	5,677				65,408,000	104.91%	NCPA & WESTERN
CITY OF SHASTA LAKE			6.00	9,827				65,113,000	108.70%	
CITY OF NEEDLES			7.40	12,000	1,020,000	337		64,841,448	130.76%	WAPA & NEVADA POWER CO.
GRIDLEY MUNICIPAL UTILITIES			9.00	5,946	400,000	182		34,272,400	103.44%	USBR
BIGGS ELECTRIC DEPT.			11.32	6,760				7,030,000	117.56%	WAPA
TOTAL MUNI	3,128,530,495	319.07		155,695	3,995,145,807			26,505,882,372	57.00%	

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Table A-2, shows annual sources and uses information for electric energy: winter and summer peaks (kW); energy-source figures for net generation, utility purchases, non-utility purchases and total sources (all in gigawatt-hours, or gWh); energy-use figures for sales to consumers, sales for resale, energy provided at no charge, energy used (by the utility system, itself), energy losses (from point of generation or receipt to the customer's meter) and total disposition (all in gWh); and system load factors (average load as a percentage of peak load), loss percentages (relative to total sources) and purchases percentages. At the bottom of the table, the totals show the muni loads and operations to be just short of one-sixth those of the IOU electrics in the state, with co-op figures being minuscule. They also show that California munis purchase only non-substantial amounts of energy from non-utility sources, such as "qualifying facilities" (QFs under federal law), private power producers, etc., while California electric IOUs purchase huge amounts.[1] Another salient fact is that only Anaheim, among the comparable munis, uses substantial amounts of its energy for resale (as does Hetch-Hetchy under current operations). These figures also show that loss ratios for the munis are much lower than for the electric IOUs, although some of that difference is explained by the fact that munis purchase much more of their energy at voltage levels and acceptance points close to those of the loads they serve. The munis also have somewhat lower load factors. Finally, all munis are greatly dependent upon power purchases from other utilities, while only SDG&E among the California electric IOUs is: PG&E and SCE purchase 3% - 5%, LADWP and SDG&E purchase just under 50% of their total electricity, and all other munis and co-ops purchase over 70%.

[1] A 1988 study by two authors of this report, Knecht and McCann, for the California Energy Commission, found that the main reason for this result from the muni side was their low avoided costs. From the IOU side, of course, the main reason is that the CPUC required them to sign huge numbers and capacities of "standard offer" contracts with very attractive terms for the sellers, before concluding that the utilities had over-committed to these resources (a mandated over-commitment that has raised ratepayer bills substantially and provided the source of much of PG&E and the other IOU's stranded costs).

UTILITY NAME	STATE	OWNER	WINTER PEAK	SUMMER PEAK	NET GENERATION	UTILITY PURCHASES	NON-UTILITY PURCHASES	TOTAL SOURCES	SALES TO CONSUMERS	SALES FOR RESALE	ENERGY NO CHARGE	ENERGY USED	ENERGY LOSSES	TOTAL DISPOSITION	LOAD FACTOR	LOSS PERCENT	UTILITY PURCHASE PCT
Plumas-Sierra Rural Elec Coop	CA	COOP	18,200	16,220	0	91,782	0	91,782	90,063	0	0	218	1,501	91,782	64 60%	1 64%	100 00%
Surprise Valley Electric Coop	CA	COOP	20,944	35,158	0	140,150	0	140,150	127,826	0	0	115	12,209	140,150	45 25%	8 71%	100 00%
Anza Electric Coop Inc	CA	COOP	5,994	7,926	0	35,958	0	35,958	31,316	0	0	80	4,562	35,958	51 73%	12 69%	100 00%
Total COOP			45,138	59,504	0	267,890	0	267,890	249,205	0	0	413	18,272	267,890	51 39%	6 82%	100.00%
Southern California Edison Co	CA	IOU	12,560,000	18,044,000	54,023,270	4,381,508	28,158,764	86,707,348	71,662,757	6,168,171	0	169,883	8,506,537	86,707,148	54 86%	9 81%	5 06%
Pacific Gas & Electric Co	CA	IOU	11,486,000	14,338,000	58,157,643	2,842,435	23,316,074	83,497,592	71,510,317	4,245,922	0	29,404	7,712,149	83,497,592	66 48%	9 24%	3 40%
San Diego Gas & Electric Co	CA	IOU	2,611,000	3,301,000	7,746,124	8,218,952	1,316,201	17,185,929	15,380,381	761,256	0	33,614	1,010,678	17,185,929	59 43%	5 88%	47 82%
Southern California Water Co	CA	IOU	14,000	21,000	0	123,582	0	123,582	110,234	0	0	0	13,348	123,582	67 18%	10 80%	100 00%
Total IOU			26,691,000	35,704,000	119,927,037	15,568,477	52,591,039	187,514,451	158,663,489	11,375,349	0	232,901	17,242,712	187,514,451	59 95%	9 20%	8 30%
Los Angeles City of	CA	MUNI	3,327,000	4,958,000	13,233,627	11,178,806	483,363	22,976,741	20,397,594	1,368,174	0	0	1,210,973	22,976,741	52 90%	5 27%	48 65%
Sacramento Municipal Util Dist	CA	MUNI	1,414,000	2,044,000	1,084,875	7,877,180	0	8,950,327	8,459,156	750	0	20,057	470,364	8,950,327	49 99%	5 26%	88 01%
Anaheim City of	CA	MUNI	349,680	513,600	960,847	2,244,165	0	3,182,597	2,243,347	784,819	0	0	154,431	3,182,597	70 74%	4 85%	70 51%
Santa Clara City of	CA	MUNI	320,000	380,000	80,503	2,225,509	0	2,306,012	2,175,703	30,197	8,912	0	91,200	2,306,012	69 27%	3 95%	96 51%
Riverside City of	CA	MUNI	263,000	441,000	323,207	1,454,420	0	1,744,224	1,576,517	128,300	0	0	39,407	1,744,224	45 15%	2 26%	83 38%
Turlock Irrigation District	CA	MUNI	187,245	302,696	287,620	1,301,419	0	1,588,024	1,206,966	281,102	0	18,719	81,237	1,588,024	59 89%	5 11%	82 08%
Pasadena City of	CA	MUNI	201,000	274,000	277,410	974,430	693	1,252,531	1,092,771	52,335	0	0	107,425	1,252,531	52 18%	8 58%	77 80%
Palo Alto City of	CA	MUNI	165,514	190,755	0	1,078,865	0	1,078,865	1,046,831	0	0	0	32,034	1,078,865	64 56%	2 97%	100.00%
Vernon City of	CA	MUNI	165,880	175,000	2,145	1,065,426	0	1,067,571	1,032,420	0	0	0	35,151	1,067,571	69 64%	3 29%	99 80%
Glendale City of	CA	MUNI	170,000	280,000	182,810	982,499	0	1,165,309	1,002,766	29,180	41,943	0	91,420	1,165,309	47 51%	7 85%	84 31%
Burbank City of	CA	MUNI	160,000	246,000	204,043	809,754	4,695	1,014,144	958,164	12,241	0	0	43,539	1,014,144	47 06%	4 29%	79 85%
Redding City of	CA	MUNI	112,600	184,900	57,046	880,460	0	937,506	653,142	236,037	0	0	48,327	937,506	57 88%	5 15%	91 92%
San Francisco City & County of	CA	MUNI	376,400	376,100	1,605,639	482,756	0	2,088,395	594,253	1,424,969	2,494	11,857	54,822	2,088,395	63 39%	2 63%	23 12%
Roseville City of	CA	MUNI	94,000	138,929	0	601,691	0	601,693	584,322	0	0	0	17,371	601,693	49 64%	2 89%	100 00%
Alameda City of	CA	MUNI	89,669	84,071	0	512,880	0	512,880	495,991	0	0	0	16,889	512,880	69 64%	3 29%	100 00%
Lodi City of	CA	MUNI	54,960	94,608	0	371,112	0	371,112	356,766	0	0	0	14,346	371,112	44 78%	3 87%	100.00%
Colton City of	CA	MUNI	33,140	53,406	0	219,687	0	219,687	208,197	0	0	0	11,490	219,687	46 96%	5 21%	100 00%
Azusa City of	CA	MUNI	29,468	46,964	0	327,005	0	327,005	187,783	120,110	2,184	0	16,908	327,005	79 49%	5 17%	100.00%
Lassen Municipal Utility Dist	CA	MUNI	25,098	22,347	0	145,126	0	145,126	132,711	0	0	600	11,815	145,126	74 33%	8 14%	100.00%
Compoc City of	CA	MUNI	24,000	20,700	0	128,941	0	128,943	118,765	0	0	0	10,178	128,943	71 11%	7 89%	100.00%
Banning City of	CA	MUNI	16,399	32,244	0	108,077	0	108,077	100,281	0	0	0	7,796	108,077	38 26%	7 21%	100.00%
Ukiah City of	CA	MUNI	16,810	25,130	6,317	85,427	0	91,944	91,944	0	0	0	0	91,944	41 77%	0 00%	93 13%
Healdsburg City of	CA	MUNI	13,114	14,727	0	65,408	0	65,408	62,350	0	0	0	3,058	65,408	50 70%	4 68%	100.00%
Needles City of	CA	MUNI	7,869	16,284	0	65,142	0	65,142	49,050	0	0	0	16,092	65,142	45 67%	24 70%	100.00%
Gridley City of	CA	MUNI	5,260	7,950	0	34,272	0	34,272	31,107	0	0	0	3,165	34,272	49 21%	9 23%	100.00%
Biggs City of	CA	MUNI	1,970	2,420	0	8,335	0	8,335	7,350	0	0	0	985	8,335	39 32%	11 82%	100.00%
Total Muni			4,119,076	5,967,811	5,072,462	24,052,390	5,386	29,055,129	24,468,853	3,100,060	55,533	51,253	1,379,430	29,055,129	55 58%	4 75%	82 78%
Muni as Percent of IOU			16 18%	16 71%	4 23%	154 49%	0 01%	15 49%	15 42%	27 25%		22 01%	8 00%	15 49%	92 70%	51 63%	997 07%

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Table A-3 shows other information: the name and telephone (voice) number of the person contacted for our survey; a summary of the demand-side-management (DSM) programs currently in place at each muni; descriptions of "lifeline" and low-income rate programs; descriptions of programs or measures to promote use of renewable generating resources; and comments on the foregoing items, rate levels or other salient points. In sum, DSM programs st the major munis (those comparable to what CCSF would be with full retail service) are similar to what they are at the California electric IOUs now. As rates and projections of rates have declined in recent years, especially with the advent of ever more extensive competition in the electric utility business; and as conservation design and equipment have become embedded in the housing and production stock and other energy prices have stabilized, DSM programs have been ever less economic at the margin and have been rolled back. For the larger munis (i.e., those comparable to SF), lifeline and low-income programs are comparable to those offered by the California electric IOUs; for the smaller munis, they are much less ambitious or lacking altogether. Consistent with the observation noted above that California electric munis purchase much less energy from non-utility sources, there appear to be no muni programs promoting renewable energy resources other than those of LADWP (which has the only significant amount of non-utility purchases) and SMUD (wind); programs for renewables and other non-utility generating sources at California electric IOUs are much larger than for other IOUs in the United States and are one reason their rates are so high.

Finally among the tables, Table A-4 shows the customer-class breakdown for the California electric munis, co-ops and IOUs. The first four columns of numbers show annual kWh sales for each utility by residential, commercial, industrial and other classes; the next four columns show these figures as a percent of total sales; and the final four columns show the total number of customers for each utility in each class. This table shows that the large munis (SMUD, Anaheim, Riverside, Glendale, Pasadena and Burbank) have slightly lower fractional residential loads, much lower commercial loads, and much higher industrial and other loads. The salient exception to these rules is LADWP, whose loads are much closer to the IOU averages than to those for munis.

TABLE A3: CALIFORNIA MUNICIPAL ELECTRIC SYSTEMS (PAGE 1 OF 2)

Municipal	Contact	DSM	Life Line Rates	Low Income Rates	Renewables	Comments
Alameda Bureau of Electricity	Terry Ambrose 510/748-3901	Educational materials, rebates for special lighting and variable speed motors, other typical DSM (ie. energy audits)	Life line and medical base line programs	No low income at this time	No incentives for renewables	Rates are 5% lower than PG&E
Anaheim Public Utilities Dept.	Ray Merchant 714/254-4249					No response as of 8/15/96
Azusa Light & Water	818/334-0215	Rebates on time of use	Life line program for the ill	No low income, no incentive, no senior rates		Small system, low rates
Biggs Electric Dept.	916/868-5493		One rate, no programs	One rate, no programs		Very low rates, small system
Burbank Public Service Dept.	Greg Simay 818/238-3550	Typical DSM program - residential energy audits, credits for lighting		Low income, disabled and senior programs	No incentive for renewable	
Colton Electric Utility	Rob Buhl 909/370-5191	DSM - energy audits, consumer rebates, refrigeration recycling, quarterly mailings	Medical base line program in place	Developing low income program		
Glendale Public Service Dept.	Valerie Epmedic 808/548-4080		No Programs	No Programs		Voting in 45-60 days on a number of different programs
Gridley Municipal Utilities	916/846-5695		No Programs	Needy can apply for aid		Very low rates compared to PG&E
Healdsburg Municipal Electric Dept.	707/431-3346					5% lower than PG&E No programs other than proven need and time of use rebates
Lodi Municipal Electric System	209/333-6762	No DSM	Medical Rates - ie. PG&E	Low Income Rates		14% lower than PG&E

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TABLE A-3: CALIFORNIA MUNICIPAL ELECTRIC SYSTEMS (PAGE 2 OF 2)

Municipal	Contact	DSM	Life Line Rates	Low Income Rates	Renewables	Comments
Los Angeles Dept. of Water and Power	Mrs. Fields 213/367-4211	DSM - rebates, energy audit, lighting	Disabled, senior rates in conjunction with City of LA	Low Income Rates in conjunction with City of LA	Incentive rebates for larger renewables	
City of Needles	619/326-5700	No DSM	Life line program, medical line	No low income, impoverished area		
Palo Alto Electric Utility	415/329-2273 Chris Wyler	DSM - energy audits	Medical - 15% water, gas or electric off bills	Financial Low Income 15% off bill, federal income standard	No incentives for renewables	
Pasadena Water & Power Corp	818/405-4409	DSM- recycling only	Disabled and Senior Rates	Low income rates		25% lower than SOCAL
Redding Electric	916/242-4400	DSM - conservation consultant	None	None		
Riverside Utilities	Ed Amboso 909/782-0330	DSM - energy conservation consultant	Life line program	Low income and share program		HEAP
Roseville Electric	916/774-5600	DSM - rebates, energy audits	Medical Rates	Low income Rates	No Incentives for renewables	
Sacramento Municipal Utility	916/452-3211	DSM - "Peak Corps" energy audits, not cost free and other programs	Medical - life support program	Low Income EAR-HEAP Energy Assistance Rebate	Wind	
Santa Clara Electric Dept.	408/984-3044 Larry Owens					No Programs Low Rates
Shasta Lake	916/275-7400	No DSM	Life line - 62 or older or disabled	No low income		Same rates as Redding
Ukiah Municipal Electric System	707/463-6200	DSM - energy audits for business and residential	Life line program	No low income rates		
Vernon Municipal Light Dept.	213/583-8811					No programs Load is entirely industrial

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TILITY NAME	STATE	OWNER	RESIDENTIAL SALES	COMMERCIAL SALES	INDUSTRIAL SALES	OTHER SALES	RESIDENTIAL PERCENT	COMMERCIAL PERCENT	INDUSTRIAL PERCENT	OTHER PERCENT	RESIDENTAL CUSTOMERS	COMMERCIAL CUSTOMERS	INDUSTRIAL CUSTOMERS	OTHER CUSTOMERS
lumas-Sierra Rural Elec Coop	CA	COOP	50,704	25,626	11,329	106	56.30%	28.45%	12.58%	0.12%	4,876	514	155	18
urprise Valley Electric Corp	CA	COOP	31,035	7,200	20,986	38,764	24.28%	5.63%	16.42%	30.33%	2,438	625	17	589
nza Electric Coop Inc	CA	COOP	21,357	7,409	0	2,550	68.20%	23.66%	0.00%	8.14%	3,201	245	0	27
otal COOP			103,096	40,235	32,315	41,420	41.37%	16.15%	12.97%	16.62%	10,515	1,384	172	634
outhern California Edison Co	CA	IOU	22,857,594	25,473,109	22,589,361	742,693	31.90%	35.55%	31.52%	1.04%	3,651,927	469,422	3,875	10,206
acific Gas & Electric Co	CA	IOU	24,325,737	30,360,631	15,761,968	1,061,781	34.02%	42.46%	22.04%	1.48%	3,788,044	542,565	1,211	16,762
an Diego Gas & Electric Co	CA	IOU	5,730,818	6,381,753	3,196,657	71,153	37.26%	41.49%	20.78%	0.46%	1,011,726	120,135	520	1,372
outhern California Water Co	CA	IOU	58,047	38,708	13,247	232	52.66%	35.11%	12.02%	0.21%	19,685	1,271	4	4
otal IOU			52,972,196	62,254,201	41,561,233	1,875,859	33.39%	39.24%	26.19%	1.18%	8,471,382	1,133,393	5,610	28,344
os Angeles City of	CA	MUNI	5,936,742	7,964,192	6,079,132	417,528	29.11%	39.04%	29.80%	2.05%	1,151,109	170,113	16,799	2,929
acramento Municipal Util Dist	CA	MUNI	3,680,243	745,035	3,961,614	72,264	43.51%	8.81%	46.83%	0.85%	417,758	44,190	7,521	1,714
naheim City of	CA	MUNI	519,177	513,070	1,124,063	87,037	23.14%	22.87%	50.11%	3.88%	87,706	14,646	571	653
anta Clara City of	CA	MUNI	205,254	83,976	1,867,360	19,113	9.43%	3.86%	85.83%	0.88%	38,488	5,230	1,566	668
iverside City of	CA	MUNI	544,869	402,326	582,132	47,190	34.56%	25.52%	36.93%	2.99%	80,735	8,406	199	125
urlock Irrigation District	CA	MUNI	475,240	107,923	510,844	112,959	39.37%	8.94%	42.32%	9.36%	51,702	5,866	1,247	4,399
asadena City of	CA	MUNI	275,898	140,812	625,936	50,125	25.25%	12.89%	57.28%	4.59%	48,752	7,405	905	173
alo Alto City of	CA	MUNI	154,867	362,046	462,429	67,489	14.79%	34.58%	44.17%	6.45%	24,597	2,400	190	196
ernon City of	CA	MUNI	123	223,112	799,745	9,440	0.01%	21.61%	77.46%	0.91%	27	1,009	930	105
lendale City of	CA	MUNI	334,455	312,826	346,191	9,294	33.35%	31.20%	34.52%	0.93%	70,124	12,097	193	4
urbank City of	CA	MUNI	237,201	230,095	459,202	31,866	24.75%	24.01%	47.92%	3.33%	43,945	6,240	211	44
edding City of	CA	MUNI	304,221	294,666	25,321	28,934	46.58%	45.12%	3.88%	4.43%	30,070	4,930	573	466
an Francisco City & County of	CA	MUNI	0	490	0	593,763	0.00%	0.08%	0.00%	99.92%	0	6	0	2
oseville City of	CA	MUNI	191,366	168,421	192,548	31,987	32.75%	28.82%	32.95%	5.47%	22,999	3,019	30	122
lameda City of	CA	MUNI	130,038	174,850	179,713	11,390	26.22%	35.25%	36.23%	2.30%	27,976	3,149	3	249
odi City of	CA	MUNI	123,548	121,330	102,151	9,737	34.63%	34.01%	28.63%	2.73%	18,910	2,920	26	262
olton City of	CA	MUNI	75,851	78,969	45,467	7,910	36.43%	37.93%	21.84%	3.80%	14,758	1,649	18	139
zusa City of	CA	MUNI	60,727	62,994	58,789	5,273	32.34%	33.55%	31.31%	2.81%	12,544	1,293	30	177
assen Municipal Utility Dist	CA	MUNI	66,171	41,408	19,617	5,515	49.86%	31.20%	14.78%	4.16%	8,281	1,198	3	1,438
ompoc City of	CA	MUNI	53,354	52,856	0	12,555	44.92%	44.50%	0.00%	10.57%	12,849	1,300	0	62
anning City of	CA	MUNI	44,159	39,098	8,903	8,121	44.04%	38.99%	8.88%	8.10%	7,905	808	8	103
kiah City of	CA	MUNI	33,950	52,835	0	5,159	36.92%	57.46%	0.00%	5.61%	6,018	1,660	0	68
ealdsburg City of	CA	MUNI	21,339	37,468	3,034	509	34.22%	60.09%	4.87%	0.82%	3,759	849	1	24
eedles City of	CA	MUNI	22,107	25,925	741	277	45.07%	52.85%	1.51%	0.56%	2,557	580	3	2
ridley City of	CA	MUNI	10,343	20,764	0	0	33.25%	66.75%	0.00%	0.00%	1,729	331	0	0
iggs City of	CA	MUNI	3,870	1,483	1,997	0	52.65%	20.18%	27.17%	0.00%	580	45	3	0
otal Muni			7,568,371	4,294,778	11,377,797	1,227,907	30.93%	17.55%	46.50%	5.02%	1,034,789	131,226	14,231	11,195
uni as Percent of IOU			14.29%	6.90%	27.38%	65.46%	92.64%	44.73%	177.51%	424.45%	12.22%	11.58%	253.67%	39.50%

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Chart A-1 presents comparisons for residential rates. Averages for 1994 for PG&E and SCE are nearly identical, both rounding to 12.3 cents/kWh, while that for SDG&E, at 11 cents/kWh, is only 90% as high. Chart A-2 shows that residential electric rates in California for all major munis are significantly (and sometimes greatly) lower than those for all major IOUs, and as a result the muni weighted average residential rate is only three-quarters (75.1%) of that for IOUs. Chart A-3 presents a comparison of muni and IOU electric-utility residential rate levels for each state. Because PG&E and SCE serve the lion's share of the California loads and their residential-rate averages are so similar, the muni/IOU weighted average comparison is 75.7%, as shown by Chart A-4. The national average value was 74.4%.

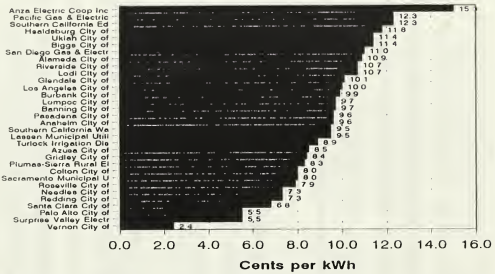
Chart A-5 shows 1994 commercial-rate comparisons. Here, PG&E splits its Southern California IOU brethren, at 11 cents/kWh, with SDG&E charging 9.7 cents/kWh (88.1%) and SCE charging 12 cents/kWh (108.3%). Commercial rates for all major munis are significantly (and sometimes greatly) lower than those for PG&E and SCE, while those of SDG&E fall right in the middle of the muni mainstream. As a result of all this, the weighted average commercial rate for munis is only 86.1% of that for PG&E. Chart A-6 shows it is 81.6% of weighted-average IOU commercial rates in the state; the national ratio is 83.9%. Chart A-11 presents a comparison of muni and IOU electric-utility industrial rate levels for each state. Chart A-8 shows California's muni/IOU commercial-rate comparison to be just below the national average, with both in the low-80% range.

Chart A-9 displays 1994 comparisons for industrial rates. Here again, PG&E splits its Southern California IOU neighbors, at 7 cents/kWh, but they lie on the opposite sides: SDG&E averages 7.5 cents/kWh (106.1%) and SCE averages 6.6 cents/kWh (94.2%). Industrial rates for all major munis are significantly (and sometimes greatly) higher than those of all IOUs, with one exception: SMUD's industrial rates are slightly below SDG&E's. As a result, the weighted average industrial rate for munis is 109.5% of that for PG&E, as shown in Chart A-10. Chart A-11 presents a comparison of muni and IOU electric-utility industrial rate levels for each state. Finally, Chart A-12 shows it is 112.5% of the weighted-average IOU industrial rate in California; the national muni/IOU industrial-rate comparison is 108.4%.

Chart 1-4: California Residential Rates

Residential Revenue per kWh

A-1



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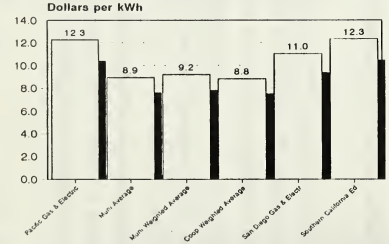
Residential Revenue per kWh



← A-2 →

Residential Rate as Pct of PG&E

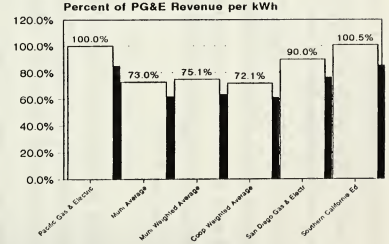
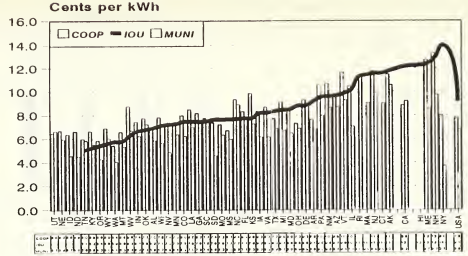


Chart 1-5: Residential State by State Analysis

Residential Revenue per kWh

A-3



Muni as Percent of IOU
Residential Rates

A-4

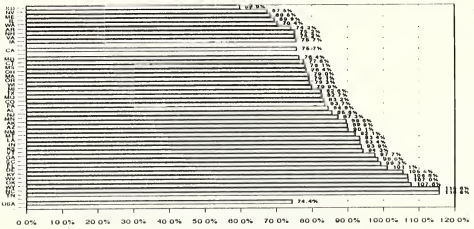


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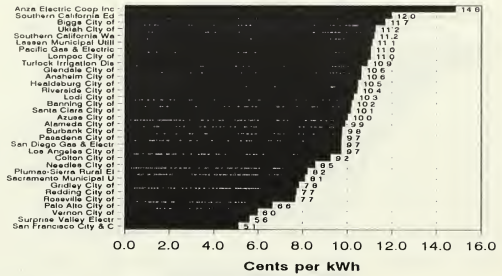
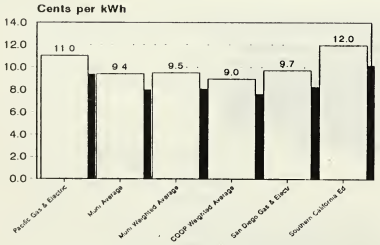
Chart 1-6: California Commercial Rates

Commercial Revenue per kWh


Anza Electric Coop Inc 14.8
Southern California Ed 12.0
Biggs City of 11.7
Ukiah City of 11.2
Southern California Wa 11.2
Leasen Municipal Utili 11.1
Pacific Gas & Electric 11.0
Lompoc City of 11.0
Turlock Irrigation Dis 10.9
Glendale City of 10.6
Anaheim City of 10.6
Healdsburg City of 10.5
Riverside City of 10.4
Lodi City of 10.3
Banning City of 10.2
Santa Clara City of 10.1
Azusa City of 10.0
Alameda City of 9.9
Burbank City of 9.8
Pasadena City of 9.7
San Diego Gas & Electr 9.7
Los Angeles City of 9.7
Colton City of 9.2
Needles City of 8.5
Plumas-Sierra Rural El 8.2
Sacramento Municipal U 8.1
Gridley City of 7.9
Redding City of 7.7
Roseville City of 7.7
Palo Alto City of 6.6
Vernon City of 6.0
Surprise Valley Electr 5.6
San Francisco City & C 5.1
0.0 2.0 4.0 6.0 8.0 10.0 12.0 14.0 16.0
Cents per kWh

A-5

Commercial Revenue per kWh



← A-6 →

Commmercial Rate as Pct of PG&E

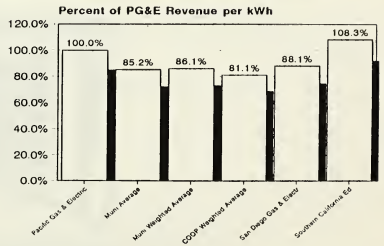


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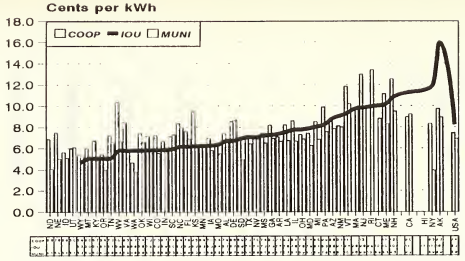
Chart 1-7: Commercial State by State Analysis

Commercial Revenue per kWh

A-7



Muni as Percent of IOU
Commercial Rates

A-8

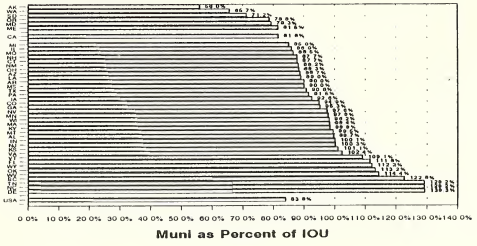


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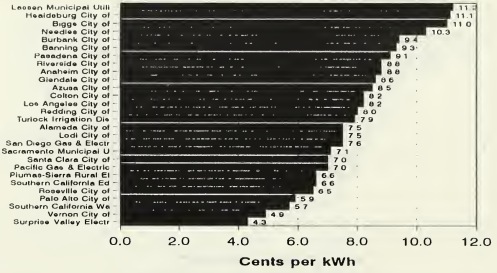
Chart 1-8: California Industrial Rates

Industrial Revenue per kWh


Lassen Municipal Utili 11.3
Healdsburg City of 11.1
Biggs City of 11.0
Needles City of 10.3
Burbank City of 9.4
Banning City of 9.3
Pasadena City of 9.1
Riverside City of 8.8
Anaheim City of 8.8
Glendale City of 8.6
Azusa City of 8.5
Colton City of 8.2
Los Angeles City of 8.2
Redding City of 8.0
Turlock Irrigation Dis 7.9
Alameda City of 7.5
Lodi City of 7.5
San Diego Gas & Electr 7.6
Sacramento Municipal U 7.1
Santa Clara City of 7.0
Pacific Gas & Electric 7.0
Plumas-Sierra Rural El 6.6
Southern California Ed 6.6
Roseville City of 6.5
Palo Alto City of 5.9
Southern California Wa 5.7
Vernon City of 4.9
Surprise Valley Electr 4.3
0.0 2.0 4.0 6.0 8.0 10.0 12.0
Cents per kWh

A-9

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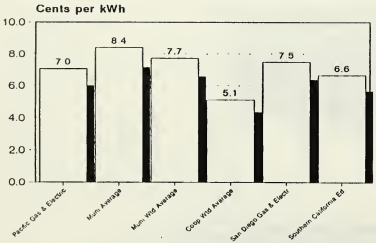
Industrial Revenue per kWh



← A-10 →

Industrial Rate as Percent of PG&E

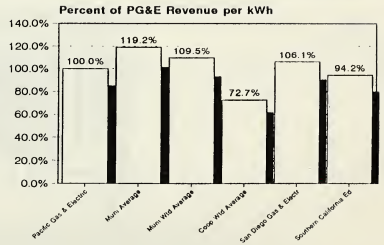
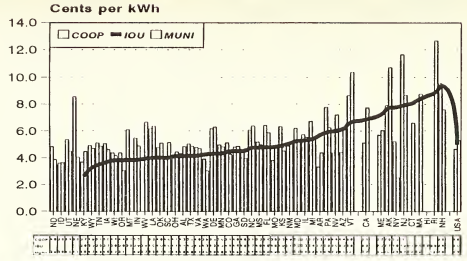
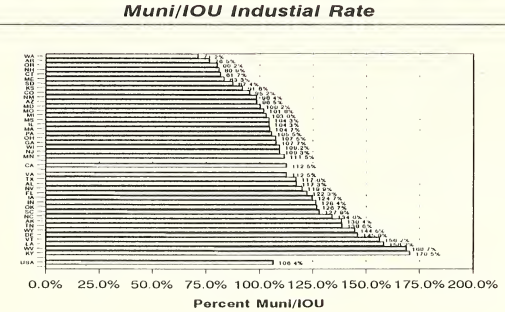


Chart 1-9: Industrial State by State Analysis

A-11



A-12



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UTILITY	NUMBER OF CUSTOMERS	KWHR SOLD	MW CAPACITY OWNED	SUMMER PEAK KW	WINTER PEAK KW	SUMMER/ WINTER	PEAK
PACIFIC GAS AND ELECTRIC CO.	4,348,611	71,510,117,000	14,970,000	14,338,000	11,486,000	SUMMER	14,338,000
SAN DIEGO GAS & ELECTRIC CO.	1,138,840	16,141,637,000	2,416,000	2,850,000	2,642,000	SUMMER	2,850,000
SOUTHERN CALIFORNIA EDISON CO.	4,150,863	77,985,856,000	15,855,462	18,044,000	12,560,000	SUMMER	18,044,000
TOTAL	9,638,314	165,637,610,000	33,241,462	35,232,000	26,688,000	SUMMER	35,232,000

MUNICIPAL	NUMBER OF CUSTOMERS	KWHR SOLD	MW CAPACITY OWNED	SUMMER PEAK KW	WINTER PEAK KW	SUMMER/ WINTER	PEAK
LOS ANGELES DEPT OF WATER & POWER	1,340,582	21,718,767,463	7,394,100	4,958,000	3,414,000	SUMMER	4,958,000
SACRAMENTO MUNICIPAL UTILITY DISTRICT	473,343	8,459,156,000	902,600	2,052,000	1,453,000	SUMMER	2,052,000
ANAHEIM PUBLIC UTILITIES DEPT.	103,545	2,943,086,548	157,687	467,040	368,640	SUMMER	467,040
SANTA CLARA ELECTRIC DEPT.	45,952	2,175,703,229	85,920	381,600		SUMMER	381,600
RIVERSIDE UTILITIES DEPT.	88,628	1,563,256,000	38,000	441,000	263,000	SUMMER	441,000
HETCH HETCHY WATER & POWER	19	1,428,473,869	389,500	376,400	376,100	SUMMER	376,400
PASADENA WATER AND POWER DEPT.	57,681	1,117,046,000	205,000	274,000	186,000	SUMMER	274,000
PALO ALTO ELECTRIC UTILITY	27,249	1,053,331,348		190,755	160,954	SUMMER	190,755
VERNON MUNICIPAL LIGHT DEPT.	1,977	1,029,598,000		174,279	169,608	SUMMER	174,279
GLENDALE PUBLIC SERVICE DEPT.	82,186	996,211,396	279,000	240,000	170,000	SUMMER	240,000
BURBANK PUBLIC SERVICE DEPT.	50,772	958,364,000	346,400	246,000	149,000	SUMMER	246,000
REDDING ELECTRIC DEPT.	34,431	689,289,000	3,530	182,286	120,231	SUMMER	182,286
ROSEVILLE ELECTRIC DEPT.	26,271	580,156,540		138,929	94,000	SUMMER	138,929
ALAMEDA BUREAU OF ELECTRICITY	31,377	495,991,410		84,071	89,669	WINTER	89,669
LODI MUNICIPAL ELECTRIC SYSTEM	21,998	361,898,000		101,150	56,258	SUMMER	101,150
COLTON ELECTRIC UTILITY DEPT.	16,564	208,197,150		54,864	46,674	SUMMER	54,864
AZUSA LIGHT & WATER DEPT.	14,134	186,680,140		47,520	27,648	SUMMER	47,520
LOMPOC UTILITY SERVICES/ELECTRICAL	14,284	117,753,305		18,608	23,378	WINTER	23,378
BANNING ELECTRIC DEPT.	9,633	106,457,461		28,440	16,400	SUMMER	28,440
UKIAH MUNIC ELECTRIC SYSTEM	7,054	101,000,000	3,500	26,300	23,000	SUMMER	26,300
HEALDSBURG MUNIC ELECTRIC DEPT.	4,693	62,347,000		14,860	12,260	SUMMER	14,860
CITY OF SHASTA LAKE	3,854	59,904,000		13,575	11,826	SUMMER	13,575
CITY OF NEEDLES	3,029	49,589,013		16,300	7,900	SUMMER	16,300
GRIDLEY MUNICIPAL UTILITIES	2,195	33,133,239		8,079	4,720	SUMMER	8,079
BIGGS ELECTRIC DEPT.	621	5,980,000		554	816	WINTER	816
TOTAL MUNI	2,462,072	46,501,370,111	9,805,237	10,536,610	7,245,082		10,547,240
MUNI AS PERCENT OF IOU	25.54%	28.07%	29.50%	29.91%	27.15%		29.94%

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	CA Munis					US Munis		
YEAR	REVTS	MWHS			YEAR	RVTS	MWHS	
1985	2,615,096	43,356,926	0.0603		1985	15,808,572	291,887,446	0.0542
1986	2,391,274	33,768,019	0.0708		1986	14,793,315	256,311,092	0.0577
1987	2,421,458	34,885,481	0.0694		1987	15,512,493	266,514,603	0.0582
1988	2,642,179	35,891,270	0.0736		1988	16,493,854	277,629,060	0.0594
1989	2,867,300	36,762,245	0.0780		1989	17,207,094	285,713,361	0.0602
1990	3,030,650	37,439,172	0.0809		1990	18,012,839	295,282,213	0.0610
1991	2,984,891	37,040,972	0.0806		1991	18,406,131	301,138,983	0.0611
1992	3,185,186	37,895,359	0.0841		1992	18,797,533	303,141,864	0.0620
1993	3,246,865	36,562,477	0.0888		1993	19,647,678	312,181,139	0.0629
1994	3,235,014	36,407,695	0.0889		1994	20,255,736	324,675,174	0.0624
	CA IOUs					US IOUs		
YEAR	REVTS	MWHS			YEAR	REVTS	MWHS	
1985	11,532,819	133,703,495	0.0863		1985	112,133,341	1,649,854,321	0.0680
1986	11,390,530	133,199,498	0.0855		1986	113,976,133	1,686,947,146	0.0676
1987	11,592,809	139,820,397	0.0829		1987	116,488,926	1,757,903,180	0.0663
1988	12,315,318	145,529,255	0.0846		1988	121,234,235	1,842,528,703	0.0658
1989	13,447,761	149,361,497	0.0900		1989	125,911,285	1,877,209,502	0.0671
1990	14,543,274	155,095,390	0.0938		1990	131,759,106	1,914,049,072	0.0688
1991	15,570,708	153,927,593	0.1012		1991	138,843,609	1,949,145,618	0.0712
1992	16,289,980	157,931,845	0.1031		1992	140,030,767	1,946,132,744	0.0720
1993	16,044,498	155,803,576	0.1030		1993	147,240,249	2,016,469,850	0.0730
1994	16,497,268	158,663,489	0.1040		1994	150,061,677	2,062,327,451	0.0728

		Revenue Comparison				
				Year		
	Utility Name	1990	1991	1992	1993	1994
IOU	Pacific Gas & Electric Co.	6,513,008	7,204,326	7,413,401	7,542,450	7,547,556
	San Diego Gas & Electric Co.	1,251,880	1.313,527	1,404,947	1,409,814	1,498,292
	Southern California Edison Co.	6,767,373	7,040,501	7,461,648	7,082,014	7,440,757
	Southern California Water Co.	11,013	12,354	9,984	10,220	10,663
IOU Total		14,543,274	15,570,708	16,289,980	16,044,498	16,497,268
Muni	Alameda City of	41,374	42,004	43,494	43,559	46,151
	Anaheim City of	196,505	192,824	209,244	206,522	210,528
	Azusa City of	17,315	17,387	17,302	17,161	16,897
	Banning City of	9,088	9,160	10,293	10,483	9,703
	Biggs City of	691	597	622	638	833
	Burbank City of	88,266	81,092	89,408	88,156	91,776
	Colton City of	16,935	16,799	16,994	17,768	17,848
	Escondido City of	5	3	4	1	4
	Glendale City of	81,166	80,539	89,537	92,715	97,618
	Gridley City of	1,926	2,397	2,548	2,430	2,490
	Healdsburg City of	5,792	6,182	6,610	6,927	6,804
	Lassen Municipal Utilty Dist.	13,172	13,014	13,801	13,955	13,983
	Lodi City of	27,126	29,892	34,598	34,654	34,394
	Lompoc City of	9,341	10,225	11,084	12,111	12,383
	Los Angeles City of	1,844,269	1,770,122	1,884,497	1931,206	1,900,475
	Needles City of	4,400	4,532	4,713	4,149	3,963
	Palo Alto City of	59,552	62,771	65,131	63,868	63,976
	Pasadena City of	92,263	92,669	96,894	97,661	101,912
	Redding City of	38,507	42,924	46,139	48,356	49,876
	Riverside City of	135,718	137,649	144,588	152,771	156,744
	Roseville City of	28,240	35,652	41,986	44,061	42,712
	San Francisco City & County of	27,837	30,307	31,307	24,492	33,464
	Santa Clara City of	142,731	154,161	167,727	171,369	153,921
	Turlock Irrigation District	70,398	82,012	89,829	97,814	103,038
	Ukiah City of	9,339	10,342	10,519	10,164	10,476
	Vernon City of	68,694	59,635	56,317	53,874	53,045
Muni Total		3,030,650	2,984,891	3,185,186	3,246,865	3,235,014

		Sales Comparison				
				Year		
	Utility Name	1990	1991	1992	1993	1994
IOU	Pacific Gas & Electric Co.	70,597,825	71,039,588	71,799,944	71,106,363	71,510,117
	San Diego Gas & Electric Co.	14,331,145	14,170,853	15,093,221	15,035,643	15,380,381
	Southern California Edison Co.	70,063,044	68,615,229	70,933,334	69,555,336	71,662,757
	Southern California Water Co.	103,376	101,923	105,346	106,234	110,234
IOU Total		155,095,390	153,927,593	157,931,845	155,803,576	158,663,489
Muni	Alameda City of	466,498	462,515	491,512	475,265	495,991
	Anaheim City of	2,266,993	2,173,544	2,289,337	1,836,016	2,243,347
	Azusa City of	193,535	194,027	185,221	186,680	187,783
	Banning City of	94,806	96,956	101,796	100,639	100,281
	Biggs City of	7,827	5,868	5,945	5,980	7,350
	Burbank City of	1,036,836	958,498	997,639	962,180	958,364
	Colton City of	197,671	194,220	194,527	204,527	208,197
	Escondido City of	377	232	329	124	404
	Glendale City of	978,034	951,334	1,017,801	996,212	1,002,766
	Gridley City of	27,000	27,900	29,300	27,900	31,107
	Healdsburg City of	60,100	58,074	61,029	61,269	62,350
	Lassen Municipal Utilty Dist.	115,330	125,094	122,899	127,774	132,711
	Lodi City of	342,293	352,363	361,398	361,898	356,766
	Lompoc City of	105,486	108,933	110,570	115,789	118,765
	Los Angeles City of	21,742,536	21,476,528	21,819,784	21,136,557	20,397,594
	Needles City of	53,601	55,892	57,237	51,618	49,050
	Palo Alto City of	1,051,705	1,026,756	1,053,556	1,045,096	1,046,831
	Pasadena City of	1,072,932	1,063,321	1,098,070	1,081,851	1,092,771
	Redding City of	607,292	635,975	649,078	635,529	653,142
	Riverside City of	1,491,251	1,470,064	1,546,756	1,545,424	1,576,517
	Roseville City of	398,889	475,594	537,573	543,450	584,322
	San Francisco City & County of	554,506	617,864	615,319	557,523	594,253
	Santa Clara City of	2,275,427	2,234,024	2,240,450	2,214,915	2,175,703
	Turlock Irrigation District	1,158,257	1,173,799	1,189,622	1,170,118	1,206,966
	Ukiah City of	92,216	92,200	91,132	88,545	91,944
	Vernon City of	1,047,774	1,099,397	1,027,479	1,029,598	1,032,420
Muni Total		37,439,172	37,040,972	37,895,359	36,562,477	36,407,695

		Rate Comparison				
				Year		
Utility Type	Utility Name	1990	1991	1992	1993	1994
IOU	Pacific Gas & Electric Co	0.0923	0.1014	0.1033	0.1061	0.1055
	San Diego Gas & Electric Co	0.0874	0.0927	0.0931	0.0938	0.0974
	Southern California Edison Co	0.0966	0.1026	0.1052	0.1018	0.1038
	Southern California Water Co	0.1065	0.1212	0.0948	0.0962	0.0967
Muni	Alameda City of	0.0887	0.0908	0.0885	0.0917	0.0930
	Anaheim City of	0.0867	0.0887	0.0914	0.1125	0.0938
	Azusa City of	0.0895	0.0896	0.0934	0.0919	0.0900
	Banning City of	0.0959	0.0945	0.1011	0.1042	0.0968
	Biggs City of	0.0883	0.1017	0.1046	0.1067	0.1133
	Burbank City of	0.0851	0.0846	0.0896	0.0916	0.0958
	Colton City of	0.0857	0.0865	0.0874	0.0869	0.0857
	Escondido City of	0.0133	0.0129	0.0122	0.0081	0.0099
	Glendale City of	0.0830	0.0847	0.0880	0.0931	0.0973
	Gridley City of	0.0713	0.0859	0.0870	0.0871	0.0800
	Healdsburg City of	0.0964	0.1065	0.1083	0.1131	0.1091
	Lassen Municipal Utility Dist	0.1142	0.1040	0.1123	0.1092	0.1054
	Lodi City of	0.0792	0.0848	0.0957	0.0958	0.0964
	Lompoc City of	0.0886	0.0939	0.1002	0.1046	0.1043
	Los Angeles City of	0.0848	0.0824	0.0864	0.0914	0.0932
	Needles City of	0.0821	0.0811	0.0823	0.0804	0.0808
	Palo Alto City of	0.0566	0.0611	0.0618	0.0611	0.0611
	Pasadena City of	0.0860	0.0872	0.0882	0.0903	0.0933
	Redding City of	0.0634	0.0675	0.0711	0.0761	0.0764
	Riverside City of	0.0910	0.0936	0.0935	0.0989	0.0994
	Roseville City of	0.0708	0.0750	0.0781	0.0811	0.0731
	San Francisco City & County of	0.0502	0.0491	0.0509	0.0439	0.0563
	Santa Clara City of	0.0627	0.0690	0.0749	0.0774	0.0707
	Turlock Irrigation District	0.0608	0.0699	0.0755	0.0836	0.0854
	Ukiah City of	0.1013	0.1122	0.1154	0.1148	0.1139
	Vernon City of	0.0656	0.0591	0.0548	0.0523	0.0514

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		Rate Comparison Sorted by 1994 Total Rates				
				Year		
Utility Type	Utility Name	1990	1991	1992	1993	1994
Muni	Escondido City of	0.0133	0.0129	0.0122	0.0081	0.0099
Muni	Vernon City of	0.0656	0.0591	0.0548	0.0523	0.0514
Muni	San Francisco City & County of	0.0502	0.0491	0.0509	0.0439	0.0563
Muni	Palo Alto City of	0.0566	0.0611	0.0618	0.0611	0.0611
Muni	Santa Clara City of	0.0627	0.0690	0.0749	0.0774	0.0707
Muni	Roseville City of	0.0708	0.0750	0.0781	0.0811	0.0731
Muni	Redding City of	0.0634	0.0675	0.0711	0.0761	0.0764
Muni	Gridley City of	0.0713	0.0859	0.0870	0.0871	0.0800
Muni	Needles City of	0.0821	0.0811	0.0823	0.0804	0.0808
Muni	Turlock Irrigation District	0.0608	0.0699	0.0755	0.0836	0.0854
Muni	Colton City of	0.0857	0.0865	0.0874	0.0869	0.0857
Muni	Azusa City of	0.0895	0.0896	0.0934	0.0919	0.0900
Muni	Alameda City of	0.0887	0.0908	0.0885	0.0917	0.0930
Muni	Los Angeles City of	0.0848	0.0824	0.0864	0.0914	0.0932
Muni	Pasadena City of	0.0860	0.0872	0.0882	0.0903	0.0933
Muni	Anaheim City of	0.0867	0.0887	0.0914	0.1125	0.0938
Muni	Burbank City of	0.0851	0.0846	0.0896	0.0916	0.0958
Muni	Lodi City of	0.0792	0.0848	0.0957	0.0958	0.0964
IOU	Southern California Water Co	0.1065	0.1212	0.0948	0.0962	0.0967
Muni	Banning City of	0.0959	0.0945	0.1011	0.1042	0.0968
Muni	Glendale City of	0.0830	0.0847	0.0880	0.0931	0.0973
IOU	San Diego Gas & Electric Co	0.0874	0.0927	0.0931	0.0938	0.0974
Muni	Riverside City of	0.0910	0.0936	0.0935	0.0989	0.0994
IOU	Southern California Edison Co	0.0966	0.1026	0.1052	0.1018	0.1038
Muni	Lompoc City of	0.0886	0.0939	0.1002	0.1046	0.1043
Muni	Lassen Municipal Utility Dist	0.1142	0.1040	0.1123	0.1092	0.1054
IOU	Pacific Gas & Electric Co	0.0923	0.1014	0.1033	0.1061	0.1055
Muni	Healdsburg City of	0.0964	0.1065	0.1083	0.1131	0.1091
Muni	Biggs City of	0.0883	0.1017	0.1046	0.1067	0.1133
Muni	Ukiah City of	0.1013	0.1122	0.1154	0.1148	0.1139

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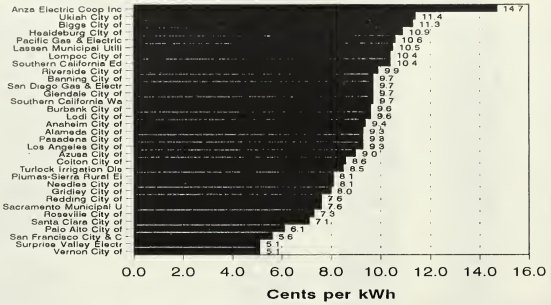
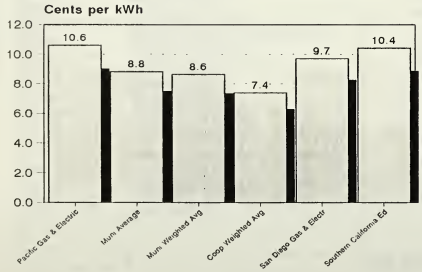
Chart 1-1: California Electric Rates

Total Revenue per kWh



Total Revenue per kWh



Total Rate as Percent of PG&E

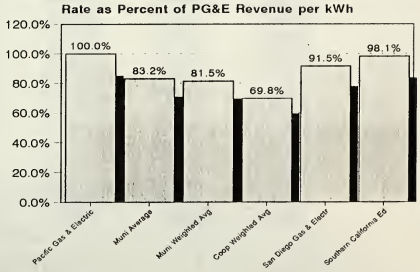
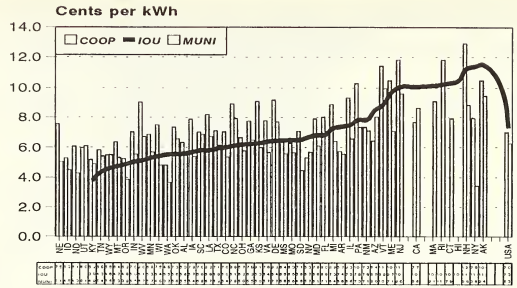


Chart 1-2: Total Rate State by State Analysis

Total Revenue per kWh



Muni as Percent of IOU
Total Revenue per kWh

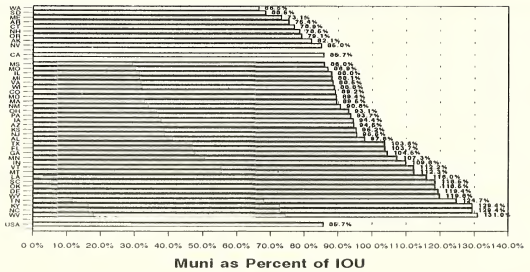


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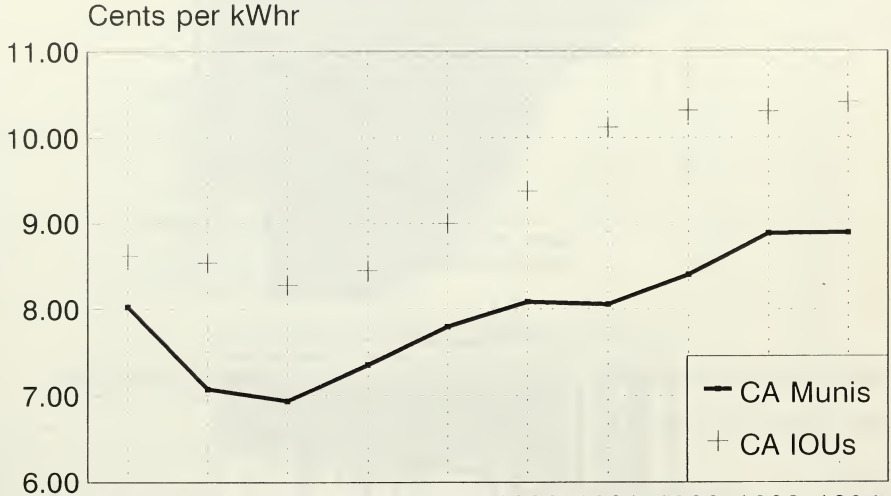
Chart 1-3: California Muni/IOU Electric Rate Comparison



CA Munis	8.03	7.08	6.94	7.36	7.80	8.09	8.06	8.41	8.88	8.89
CA IOUs	8.63	8.55	8.29	8.46	9.00	9.38	10.12	10.31	10.30	10.40

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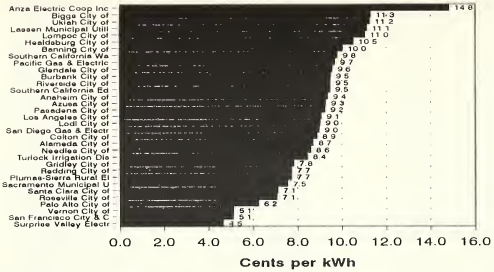
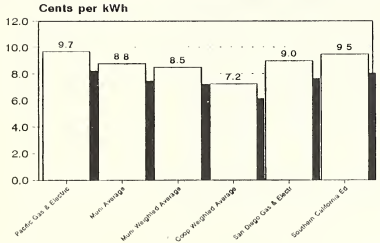
Chart 1-10: California Business Rates

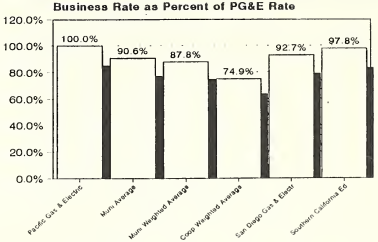
Business Revenue per kWh


Anza Electric Coop Inc 14.8
Biggs City of 11.3
Ukiah City of 11.2
Lassen Municipal Util 11.1
Lompoc City of 11.0
Healdsburg City of 10.5
Banning City of 10.0
Southern California Wa 9.8
Pacific Gas & Electric 9.7
Glendale City of 9.6
Burbank City of 9.5
Riverside City of 9.5
Southern California Ed 9.5
Anaheim City of 9.4
Azusa City of 9.3
Pasadena City of 9.2
Los Angeles City of 9.1
Lodi City of 9.0
San Diego Gas & Electr 9.0
Colton City of 8.9
Alameda City of 8.7
Needles City of 8.6
Turlock Irrigation Dis 8.4
Gridley City of 7.8
Redding City of 7.8
Plumas-Sierra Rural El 7.7
Sacramento Municipal U 7.5
Santa Clara City of 7.1
Roseville City of 7.1
Palo Alto City of 6.2
Vernon City of 5.1
San Francisco City & C 5.1
Surprise Valley Electr 4.9
0.0 2.0 4.0 6.0 8.0 10.0 12.0 14.0 16.0
Cents per kWh

Business Revenue per kWh



Business Rate as Pct of PG&E



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UTILITY NAME	STATE	OWNER	NON-UTILITY PURCHASE PCT	GENERATION PERCENT
Plumas-Sierra Rural Elec Coop	CA	COOP	0.00%	0.00%
Surprise Valley Electric Corp	CA	COOP	0.00%	0.00%
Anza Electric Coop Inc	CA	COOP	0.00%	0.00%
Total COOP			0.00%	0.00%
Southern California Edison Co	CA	IOU	32.48%	62.31%
Pacific Gas & Electric Co	CA	IOU	27.68%	69.65%
San Diego Gas & Electric Co	CA	IOU	7.66%	45.07%
Southern California Water Co	CA	IOU	0.00%	0.00%
Total IOU			28.05%	63.96%
Los Angeles City of	CA	MUNI	2.10%	57.60%
Sacramento Municipal Util Dist	CA	MUNI	0.00%	12.12%
Anaheim City of	CA	MUNI	0.00%	30.19%
Santa Clara City of	CA	MUNI	0.00%	3.49%
Riverside City of	CA	MUNI	0.00%	18.53%
Turlock Irrigation District	CA	MUNI	0.00%	18.11%
Pasadena City of	CA	MUNI	0.06%	22.15%
Palo Alto City of	CA	MUNI	0.00%	0.00%
Vernon City of	CA	MUNI	0.00%	0.20%
Glendale City of	CA	MUNI	0.00%	15.69%
Burbank City of	CA	MUNI	0.46%	20.12%
Redding City of	CA	MUNI	0.00%	6.08%
San Francisco City & County of	CA	MUNI	0.00%	76.88%
Roseville City of	CA	MUNI	0.00%	0.00%
Alameda City of	CA	MUNI	0.00%	0.00%
Lodi City of	CA	MUNI	0.00%	0.00%
Colton City of	CA	MUNI	0.00%	0.00%
Azusa City of	CA	MUNI	0.00%	0.00%
Lassen Municipal Utility Dist	CA	MUNI	0.00%	0.00%
Lompoc City of	CA	MUNI	0.00%	0.00%
Banning City of	CA	MUNI	0.00%	0.00%
Ukiah City of	CA	MUNI	0.00%	6.87%
Healdsburg City of	CA	MUNI	0.00%	0.00%
Needles City of	CA	MUNI	0.00%	0.00%
Gridley City of	CA	MUNI	0.00%	0.00%
Biggs City of	CA	MUNI	0.00%	0.00%
Total Muni			0.02%	17.46%

Workpapers 1.B

Muni/IOU Cost of Service Comparison

1. Introduction

The cost structure of an electric utility company can be separated into (1) generation and purchased power costs; (2) transmission costs; (3) distribution costs; (4) administrative and overhead costs; and, (5) customer service costs. Total costs are reconciled to total retail revenues using data from the Energy Information Agency form 412 for munis and the Federal Energy Regulatory Commission form 1 for IOUs. These forms separate electric operation and maintenance expenses and plant costs by functional area (production, transmission, distribution and general). Using the basic formula that total revenues equate to total costs plus operating income, both the operating expenses and capital recovery portions of revenues can be separated into functional components. Capital recovery (which for IOUs includes both income taxes and operating income and for munis includes only operating income) is split according to the amount of dollars the muni or IOU has invested in each functional category (i.e., distribution, transmission and production).

2. Customer Expenses

The first category of costs analyzed are the relative level of muni and IOU customer expenses. These expenses include customer accounts expenses, customer service and information expenses and sales expenses. For munis, the expenses are recorded on Schedule VII of the EIA Form 412 and for IOUs the expenses are recorded on page 322 of the FERC form 1. Unlike other cost categories, these expenses do not include net invested capital in the total cost. Since some of the municipal systems have a far higher ratio of residential customers than the neighboring IOU, cost comparisons are shown on the bais of cost per customer is shown as well as cost per kWhr. For example, the energy use per customer is 65% more for Cleveland Electric Illuminating (the IOU) than for Cleveland Public Power (the muni) and data on the basis of cost per kWhr will appear lower for the IOU than data computed on the basis of cost per customer.

Table B-1 shows the ratio muni to IOU of customer costs per kWhr and customer costs per customer for the six large muni/IOU pairs as well as for additional munis in California. The source for number of customers is McGraw Hill's Electric World Publications. The source data for these cost comparisons is shown in the cost of service workpaper.

TABLE B-1 *Ratio of Muni to IOU Customer Expense*		
	Muni Versus IOU Cost Per KWhr	Muni Versus IOU Cost Per Customer
SMUD/PG&E	97.45%	105.64%
CPP/CEI	81.78%	48.20%
San Antonio/TU	39.38%	25.19%
Jacksonville/FP&L	45.77%	55.05%
Seattle/Puget	129.82%	132.05%
LADWP/SCE	122.16%	95.98%
Anaheim/PG&E	62.19%	80.21%
Riverside/PG&E	61.11%	64.15%
Palo Alto/PG&E	31.93%	73.98%
Vernon/PG&E	8.63%	NA
Glendale/PG&E	75.42%	54.24%
Burbank/PG&E	26.08%	29.58%
Redding/PG&E	38.60%	43.66%
Santa Clara/PG&E	.67%	1.93%
Alameda/PG&E	58.92%	54.44%

Table B-1 shows that out of the twelve ratios computed for the six large muni/IOU systems, four cases have higher muni costs relative to the IOU and eight cases have higher IOU costs. All of the small California munis (not including Santa Clara which apparently reports the maljority of customer expenses in A&G expense) are able to provide service at lower costs than PG&E. PG&E records some DSM costs in customer information expense which could cause its cost to be higher than the other California muni systems. In summary, the analysis of customer costs demonstrates that IOUs are <u>not</u> more efficient than munis.

3. Administrative and Overhead Costs

The second category of costs analyzed is administrative and general costs. These costs are defined to include operation and maintenance costs as well as return on net capital and depreciation expense.[1] For each comparative situation, we compute the ratio of muni A&G cost

[1] Administrative and general expenses are recorded on schedule VII of the EIA form 412 for munis and on page 323 of the FERC form 1 for IOUs. Depreciation expense on general plant is recorded on page 336 of the FERC form 1 for IOUs and is allocated on the basis of plant values. General plant is shown on schedule IV of the EIA form 412 for munis and on page 207 of the FERC form for IOUs. Accumulated depreciation on general plant is from page

to the IOU A&G cost. Because capital costs are influenced by the rate of return difference between munis and IOUs, the total A&G costs are shown at both muni and IOU rates of return. Table B-2 shows the cost ratios for the muni/IOU pairs.

TABLE B-2
Ratio of Muni to IOU Total A&G Costs Including Capital Costs

	Muni Versus IOU Cost Per kWhr		Muni Versus IOU Cost Per Customer	
	At Actual Cost of Capital	At IOU Cost of Capital	At Actual Cost of Capital	At IOU Cost of Capital
SMUD/PG&E	56.17%	87.25%	60.07%	93.30%
CPP/CEI	122.16%	121.54%	72.01%	71.64%
San Antonio/TU	146.28%	157.79%	93.57%	100.94%
Jacksonville/FP&L	95.79%	107.72%	115.20%	129.56%
Seattle/Puget	20.17%	38.52%	20.51%	39.18%
LADWP/SCE	118.30%	144.66%	92.95%	113.65%
Anaheim/PG&E	20.17%	38.52%	26.01%	49.68%
Riverside/PG&E	70.60%	74.80%	74.11%	78.52%
Palo Alto/PG&E	13.95%	13.95%	32.33%	32.33%
Vernon/PG&E	33.58%	34.48%	NA	NA
Glendale/PG&E	112.21%	141.81%	80.70%	101.98%
Burbank/PG&E	73.28%	77.90%	83.11%	88.35%
Redding/PG&E	159.04%	159.04%	179.88%	179.88%
Santa Clara/PG&E	128.19%	166.39%	368.38%	478.17%
Alameda/PG&E	97.14%	110.56%	89.76%	102.16%

Table B-2 shows that if the actual costs of capital is used, in only one instance of the six large munis did the muni experience higher A&G costs than the IOU on a cost per customer basis. When the cost of capital adjustment is made, three out of the six munis had higher costs than the IOUs on a cost per customer basis and four out of the six had higher costs on a dollar per kWhr basis. Table 1-7 illustrates that for the small munis in California, the comparisons are somewhat distorted because Santa Clara appears to record customer costs in the A&G category. Furthermore, Anaheim appears to record some costs in distribution rather than A&G. Excluding Santa Clara, two of the remaining eight California munis had A&G costs comparable to PG&E,

219 of the FERC form for IOUs and is allocated for munis.

one had higher costs and five had lower costs. In sum, the A&G cost comparison does not demonstrate obvious muni/IOU cost structure differences.

4. Total Distribution Costs

Total distribution costs including O&M costs and capital costs are shown on a per kWhr and a per customer basis in Table B-3 below. As with total A&G costs, the comparisons are shown at both actual returns and returns which are equivalent for both the muni and the IOU. Table B-3 shows the ratio of muni cost to the IOU cost for each pair of utilities.

TABLE B-3
Ratio of Muni to IOU Total Distribtuion Cost

	Muni Versus IOU Cost Per kWhr		Muni Versus IOU Cost Per Customer	
	At Actual Cost of Capital	At IOU Cost of Capital	At Actual Cost of Capital	At IOU Cost of Capital
SMUD/PG&E	37.55%	79.88%	40.15%	85.42%
CPP/CEI	279.88%	277.35%	164.97%	163.47%
San Antonio/TU	102.27%	136.01%	65.42%	87.01%
Jacksonville/FP&L	74.40%	110.95%	89.48%	133.43%
Seattle/Puget	42.42%	71.34%	43.15%	72.56%
LADWP/SCE	91.39%	167.35%	71.81%	131.49%
Anaheim/PG&E	42.42%	71.34%	54.72%	92.01%
Riverside/PG&E	49.03%	83.40%	51.47%	87.54%
Palo Alto/PG&E	36.12%	101.04%	83.68%	234.12%
Vernon/PG&E	29.81%	34.15%	NA	NA
Glendale/PG&E	48.88%	93.32%	35.15%	67.11%
Burbank/PG&E	53.48%	71.85%	60.65%	81.48%
Redding/PG&E	68.42%	170.41%	77.38%	192.74%
Santa Clara/PG&E	7.05%	7.05%	20.27%	20.27%
Alameda/PG&E	41.09%	71.20%	37.97%	65.79%

Table B-3 demonstrates that on a total distribution cost per customer basis, only one muni -- Cleveland Public Power -- had higher distribution costs than the neighboring IOU. However, distribution is a very capital intensive portion of the electric utility business and the cost comparison is strongly influenced by rate of return. If the IOU rate of return is applied to the muni cost, two of the nine small California munis had lower costs than PG&E. Using the actual rate of return, all had lower distribution costs than PG&E on both a kWhr basis and a per

customer basis. After adjusting for cost of capital differences, only two of the nine small munis had higher costs than PG&E.

5. A&G and Distribution Operation and Maintenance Costs

The capital versus operation and maintenance components can be instructive in the cost analysis. The operation and maintenance components are shown in Table B-4 and B-5 so that the differences in capital costs.

TABLE B-4
Ratio of Muni to IOU Administrative and General O&M Expense

	Muni Versus IOU Cost Per KWhr	Muni Versus IOU Cost Per Customer
SMUD/PG&E	53.89%	57.63%
CPP/CEI	77.48%	45.67%
San Antonio/TU	139.06%	88.96%
Jacksonville/FP&L	115.84%	139.32%
Seattle/Puget	116.92%	118.92%
LADWP/SCE	130.26%	102.34%
Anaheim/PG&E	6.11%	7.88%
Riverside/PG&E	89.81%	94.28%
Palo Alto/PG&E	18.22%	43.38%
Vernon/PG&E	42.09%	NA
Glendale/PG&E	129.15%	92.87%
Burbank/PG&E	91.87%	104.19%
Redding/PG&E	213.43%	241.40%
Santa Clara/PG&E	127.6%	366.69%
Alameda/PG&E	113.71%	105.07%

Table B-4 shows that there is no obvious difference between munis and IOUs in terms of A&G operation and maintnenace expense on a customer or kWhr basis. For A&G expenses, the operating expence represents a high percentage of the total cost. On the other hand, for distribution costs, the operation and maintenance is a relatively small fraction of the total cost. The distribution O&M comparison is shown on Table B-5 below.

TABLE B-5 *Ratio of Muni to IOU Distribution O&M Expense*		
	Muni Versus IOU Cost Per kWhr	Muni Versus IOU Cost Per Customer
SMUD/PG&E	53.89%	57.63%
CPP/CEI	566.67%	334.00%
San Antonio/TU	171.86%	109.94%
Jacksonville/FP&L	96.46%	116.01%
Seattle/Puget	178.04%	181.08%
LADWP/SCE	250.98%	197.19%
Anaheim/PG&E	94.47%	121.85%
Riverside/PG&E	100.72%	105.72%
Palo Alto/PG&E	150.34%	348.33%
Vernon/PG&E	101.54%	NA
Glendale/PG&E	132.04%	94.95%
Burbank/PG&E	182.04%	206.46%
Redding/PG&E	157.23%	177.84%
Santa Clara/PG&E	37.42%	107.53%
Alameda/PG&E	70.32%	64.97%

6. Total Cost Components

The total cost components on a percentage muni/IOU bsais for the six large munis and the California system are shown on Tables B-6 and B-7. This data supports Chart 1-8 and 1-9 in the report. The data source is the cost of service workpaper whihc in turn is derived from EIA form 412's for the munis and Ferc form 1's for the IOUs. The Tables below present data in terms of the ratio of muni cost per kWhr to IOU cost per kWhr.

Table B-6
Percentage Difference in Muni and IOU Costs For Munis & Neighboring IOUs (cents/kWh)

Utility	Average Total Retail Electric	Taxes (Non-Income)	Energy Production Cost	Transmission Cost	Distribution Cost	A&G Cost	Customer Costs
Sacramento Actual	69.24%	.56%	83.36%	73.58%	37.55%	56.17%	97.45%
Sacramento Adjusted	108.07%	.56%	127.12%	110.75%	79.88%	87.25%	97.45%
Cleveland Public Actual	91.64%	0%	76.88%	165.58%	297.88%	122.16%	81.78%
Cleveland Public Adjusted	91.08%	0%	76.69%	161.40%	277.35%	121.54%	81.78%
Jacksonville Actual	97.29%	96.25%	105.87%	109.49%	74.40%	95.79%	45.77%
Jacksonville Adjusted	126.92%	96.25%	141.39%	165.13%	110.95%	107.72%	45.77%
San Antonio Actual	87.13%	115.99%	78.42%	71.12%	102.27%	146.28%	39.38%
San Antonio Adjusted	106.51%	115.99%	99.54%	100.57%	136.01%	157.79%	39.38%
Los Angeles Actual	89.41%	152.56%	82.30%	60.37%	91.39%	118.30%	122.16%
Los Angeles Adjusted	115.88%	152.56%	97.39%	108.65%	167.35%	144.66%	122.16%
Seattle Actual	64.98%	0%	62.10%	53.10%	74.14%	109.80%	129.82%
Seattle Adjusted	89.80%	0%	82.79%	69.36%	129.85%	143.19%	129.82%

The percentage variance between cost components for nine relatively small munis and PG&E is shown on Table B-7 below.

Table B-7
Percentage Difference Between Small Muni and PG&E Costs

Utility	Average Total Retail Electric	Taxes (Non-Income)	Energy Production Cost	Transmission Cost	Distribution Cost	A&G Cost	Customer Costs
Anheim Actual	93.97%	139.61%	120.25%	142.98%	42.42%	20.17%	62.19%
Anheim Adjusted	115.99%	139.61%	144.01%	154.71%	71.34%	38.52%	62.19%
Riverside Actual	99.35%	342.75%	103.89%	199.22%	49.03%	70.60%	61.11%
Riverside Adjusted	113.74%	342.75%	114.96%	214.20%	83.40%	74.80%	61.11%
Palo Alto Actual	36.34%	296.53%	47.64%	--	36.12%	13.95%	31.93%
Palo Alto Adjusted	59.21%	296.53%	47.64%	--	101.04%	13.95%	31.93%
Vernon Actual	51.73%	51.29%	57.81%	146.27%	29.81%	33.58%	8.63%
Vernon Adjusted	54.94%	51.29%	58.14%	190.69%	34.15%	34.48%	8.63%
Glendale Actual	93.06%	333.20%	95.80%	68.64%	48.88%	112.21%	75.42%
Glendale Adjusted	112.69%	333.20%	102.68%	151.03%	93.32%	141.81%	75.42%
Burbank Actual	92.06%	197.99%	113.47%	18.57%	53.48%	73.28%	26.08%
Burbank Adjusted	99.07%	197.99%	117.03%	36.36%	71.85%	77.90%	26.08%
Redding Actual	73.74%	--	72.71%	--	68.42%	159.04%	38.60%
Redding Adjusted	97.77%	--	79.33%	--	170.41%	159.04%	38.60%
Alemeda Actual	88.19%	266.45%	101.64%	12.42%	41.09%	97.14%	58.92%
Alemeda Adjusted	96.08%	266.45%	101.64%	25.20%	71.20%	110.56%	58.92%
Santa Clara Actual	74.60%	--	102.79%	1.65%	7.05%	128.19%	.67%
Santa Clara Adjusted	84.42%	--	112.93%	1.65%	7.05%	166.39%	.67%

7. Discussion of Muni/IOU comparisons for Six Large Systems

In the remainder of these workpapers, we discuss the comparison of costs for IOUs and munis for the six large systems. Details of the costs and sources of individual numpers can be obtained from the workpaper. We have contacted the muni systems to request confirmation of the accuracy of the descriptions of reasons for cost differences. The discussion of PG&E versus SMUD is somewhat more lengthy than the other discussions.

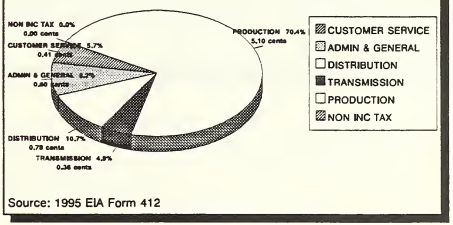
A. SMUD v. PG&E

a. SMUD and PG&E Financing Cost and Functional Cost Separation

In 1995, SMUD incurred a loss of $34.5 million (page 3 of its EIA form 412) while PG&E earned a net profit of $1.339 billion (FERC form 1, page 117). SMUD had equity of $216 million which means it earned a return of negative 16% return on equity. The amount of long and short term debt outstanding for SMUD was $2.711 billion (its ratio of debt to capital is about 93%). PG&E had equity of $9.14 billion which means it earned a return of 14.6%. Furthermore, whereas SMUD's income includes no deduction for income taxes, PG&E recorded $985 million in 1995 of current and deferred taxes.

PG&E collected $2.33 billion from consumers over and above costs of operation and maintenance expenses and depreciation which amounts to a 17.5% rate of return on its net assets. On the other hand, SMUD charged its consumers only $66.8 million above the operation and maintenance and depreciation costs which resulted in a pre-tax return of 2.9%.[2] Because of the very significant difference between return levels, the relative cost structure of SMUD and PG&E is analyzed by applying the same rate of return to both PG&E and SMUD as well as using the actual return levels for both systems. By applying this methodology, the cost of capital productivity can be separated from other productivity issues in managing operating costs and capital costs.

Chart B-1
Sacremento Municipal Utility District
Cost Structure Components



Source: 1995 EIA Form 412

Chart B-1 shows the cost breakdown for SMUD in terms of the non-income tax, production, transmission, distribution, A&G and customer service. This chart is analogous to Chart 1-6 presented in the chapter.

[2] The net assets are from the FERC form 1 and EIA form 412. These numbers are the dollars of gross plant investment less the accumulated depreciation.

b. Distribution, Customer and Administrative Costs for SMUD and PG&E

Comparative SMUD and PG&E administrative costs, customer expenses and distribution costs are shown in Table 1-4 and Table 1-5 below. Since all of these cost categories can be influenced to a certain extent by the number of customers irrespective of energy usage[3], the data is presented on both a cost per kWhr basis and a cost per customer basis. The total distribution costs and total A&G costs include both operation and maintenance costs as well as the annual costs associated with covering the capital investment (depreciation expense and pre-tax return on net investment). For A&G, based on net investment in general plant and for distribution, the capital investment is based on distribution gross plant less accumulated depreciation.

TABLE 1-6
Administrative, Customer and Distribution Costs Per KWHR

	SMUD (Cents Per kWhr)	PG&E (Cents Per kWhr)	SMUD As Percent of PG&E
Customer Expenses Per kWhr	.414	.424	97.45%
A&G O&M Cost Per kWhr	.792	.427	53.89%
A&G Total Cost Per kWhr at Actual Cost of Capital	.597	1.063	56.17%
A&G Total Cost Per kWhr at PG&E Cost of Capital	.928	1.063	87.25%
Distribution O&M Per kWhr	.390	.325	83.46%
Distribution Total Cost Per kWhr of Actual Cost of Capital	.776	2.068	37.55%
Total Distribution Cost at PG&E Cost of Capital	1.652	2.068	79.88%

[3] The costs of administering a customer bill and meter reading are similar whether a customer uses 500 kWh per month or 1,000 kWh per month.

TABLE 1-7
Administrative, Customer and Distribution Costs Per Customer

	SMUD ($ Per Customer)	PG&E ($ Per Customer)	SMUD as Percent of PG&E
Customer Expenses Per kWhr	$72.923	$67.76	104.21%
A&G O&M Cost Per kWhr	57.370	64.26	89.26%
A&G Total Cost Per kWhr at Actual Cost of Capital	75.270	130.59	57.63%
A&G Total Cost Per kWhr at PG&E Cost of Capital	136.88	340.92	40.15%
Distribution O&M Per kWhr	291.21	340.92	85.42%
Distribution Total Cost Per kWhr of Actual Cost of Capital	105.28	175.28	60.07%
Total Distribution Cost at PG&E Cost of Capital	163.52	175.26	93.30%

Table B-6 and B-7 demonstrate that for all categories of customer, distribution and A&G cost, SMUD has achieved lower costs than PG&E except customer expenses measured on the basis of number of customers served. Furthermore, these cost advantages for SMUD are present even after considering cost of capital differences. A possible explanation for PG&E's high distribution costs may be that the population density in its service area is only one-tenth of that in SMUD's service area; this conclusion is not clear, though, because large parts of PG&E's service area are agricultural and mountain terrain not actually served by distribution lines.

c. SMUD versus PG&E Production and Transmission Cost

Differences between SMUD and PG&E in terms of transmission and production costs have less importance to the municipalization study because in a forward looking municipalization analysis, the historical decisions that led to the current status of production costs either will not be relevant to SF consumers in a municipalization scenario, or, in the case of PG&E, may not be avoidable due to federal and state policies on stranded investment.

A notable other feature of this comparison is that energy-supply and distribution costs are very high for both of these utilities, as compared to the other IOUs and munis analyzed; the only comparably high figures are found for two other California utilities (SCE and LADWP) and CPP, as discussed below. As shown in Table 1-2 and discussed in the first section, however, PG&E's costs are only somewhat above the state IOU average, while those for SMUD are significantly below the state muni average. This comparison shows that munis can have lower costs for all major components of electric-utility service -- although the vast majority of SMUD's advantage lies in its lower gross cost of capital.

B. Cleveland: CPP v. CEI

The CPP/CEI cost structure comparison is interesting because expansions by CPP is a form of partial municipalizations and because CPP and CEI have direct retail competition. CPP could be analogous to a partial municipalization by San Francisco. CPP has about 66,000 customers compared to the SF estimate of 331,000 in SF. CPP has historically had an acrimonious relationship with CEI. For example, in its annual report, CPP stated:

> "More and more Clevelanders are turning to CPP as they realize the cost-saving benefits of electricity rates that are 30% lower than those of CEI. In 1993, we saved our customers $24.9 million, a figure that reflects the additional dollars CPP customers would have had to pay if they were buying power from CEI."
>
> "A late-season blizzard in March and a ferocious, record-breaking thunderstorm in July had our employees working day and night, around the clock, to keep electrical service flowing to our customers. While CEI's customers waited as long as 14 days for power to be restored after July's devastating storm, all CPP customers were restored to service within 96 hours. It is this kind of responsiveness, preparedness and commitment to service that has more and more Cleveland residents and business turning to CPP's low-cost power everyday. In fact, 1993 saw us with a record number of meter gains from CEI and the largers customer gain in nearly 80 years."

The rate comparison for CPP and CEI is shown in the table below.

***Rate Comparison (Cents Per kWhr)*[4]**

	CPP	CEI	CPP as Percent of CEI
Residential	8.5	10.8	78.70%
Commercial	8.2	9.4	87.23%
Industrial	5.4	6.4	84.38%
Total	7.4	8.4	88.10%
State Wide	Muni/5.8	IOU/6.2	93.55%

The cost structure comparison between CEI and CPP detailed in the cost of service workpaper demonstrates that CPP has higher relative transmission and distribution costs and lower production costs. The high non-production costs for CPP could include modest allocations

[4] 1994 Data from EIA form 861.

of legal costs in transmission-access battles that have accompanies expansion of CPP's retail service and which are not usually part of the picture -- but which may be instructive for San Francisco in considering whether to extend to full retail service. Even without these costs, CPP's T&D costs are still much higher than those for CEI and all other non-California utilities in this table, and CPP and CEI's T&D costs both lie in the range of the California utilities. Second, CEI's energy-production costs are substantially increased by problematic nuclear projects, while CPP's energy costs (almost all purchases) do not reflect any such problems. Third, CEI pays the highest non-income taxes, while CPP pays virtually none. Finally, because of the high level of capital investment in distribution property, CPP and CEI have similar rates of return.

Setting tax costs aside shows that CPP's higher costs in T&D almost exactly offset CEI's higher energy-supply costs, but they do not explain why CPP's T&D costs are so high. The statewide figures show that costs for both of these utilities are high compared to those in their region, mainly as a result of CEI's nuclear problems and CPP's T&D costs. Because CPP's costs are not driven as much as many other utilities' costs by the cost of capital (with purchases replacing asset ownership) and because CEI's earned return on capital is anomalously low as a result of its nuclear problems, the cost of capital adjustment for CPP does not make a significant difference; the rough parity between rates for the two utilities, excluding non-income taxes, shows in either comparison. These figures show that inefficiencies in different components can have comparable and off-setting effects on ratepayers in comparing munis and IOUs.

C. Jacksonville v. FP&L

Jacksonville results in Table 1-2, comparing Jacksonville's muni and Florida Power & Light (FP&L, the IOU) must be qualified only slightly. Jacksonville has 313,000 customers compared with FP&L's 3,422,000 customers. The ratio of residential to total energy sales is 43% for Jacksonville and 41% for FP&L. The use per customer is 2,386 kWhr per customer per month for Jacksonville and 1,793 for FP&L. Jacksonville has equity of $541 million and debt of $2.73 billion. Jacksonville owns the Kennedy station (250MW) completed in 1969 which burns oil and gas; the Southside station (281 MW) which burns oil and gas; the Northside station (1,350MW) which burns oil and gas; and St. James Power plant, a 1,359 MW coal station.

Figures for both utilities are representative of muni and IOU costs in that state, and they contain similar levels of non-income taxes. While neither utility has significant access to low-cost federal preference power, FP&L shows lower energy-production costs, despite having substantial nuclear capacity (actually, from having non-troubled early-vintage nuclear capacity). The muni's high costs are apparently due to high capital costs on its power plants, because its costs rise significantly when adjusted for FP&L's cost of capital and income-tax rates. Comparative rates are shown below:

Rate Comparison (Cents Per KWhr)			
	Jacksonville	FP&L	Jacksonville As Percent of FP&L
Residential	7.0	7.5	93.33%
Commercial	6.3	6.2	101.61%
Industrial	5.2	4.9	106.12%
Total	6.4	6.9	92.75%
State Wide	Muni/7.1	IOU/6.8	104.41%

The same effect is apparent for Jacksonville's transmission costs, because those costs are dominated by capital investment; one should not make too much of the difference in the raw transmission costs, because they are modest and likely are greatly affected by the geography of loads and power plants in Florida. Similarly, one should also not make too much of Jacksonville's advantage in distribution costs, especially in light of the parity of its adjusted figures with those of FP&L, because Jacksonville benefits from a service-area population density three times that of FP&L. This comparison suggests that retail ratepayers may benefit from lower distribution costs with a muni.

D. San Antonio v. TU

The comparison in Table 1-2 of San Antonio muni electric service with that of Texas Utilities (TU, the IOU serving much of the state) shows that results can be the opposite of those for Jacksonville. In this case, T&D costs are 10%-15% higher for the muni system, even though the IOU service area has a greatly lower population density. On the other hand, while both utilities have had comparable levels of problems with a nuclear plant (the South Texas project which they own in common), the lower muni cost of capital and freedom from income taxes has kept San Antonio's energy-supply costs lower than TU's; this effect shows clearly in the adjusted energy-supply number for San Antonio, because making the adjustment causes this component to rise from well below TU's value to just above it (just as it causes the T&D costs, being capital-intensive, to rise well above those for TU).

Neither utility has significant access to low-cost federal preference power, so the energy-supply costs comparisons here are generally useful in light of the similarity of nuclear experience and the fact that both utilities' costs lie on opposite sides of the statewide averages for muni and IOU costs, with TU high and San Antonio low. In sum, this comparison shows that the advantage in cost of capital and freedom from income taxes can result in lower overall and component costs for munis that operate efficiently overall, even where some components are

provided less efficiently than by the neighboring IOU, when that IOU has significant inefficiencies in some area, and even with the anomaly of a muni paying higher non-income taxes.

Rate Comparison (Cents Per KWhr)			
	San Antonio	TU	San Antonio as Percent of TU
Residential	6.6	8.2	80.49%
Commercial	6.1	6.9	88.41%
Industrial	4.6	4.3	106.98%
Total	5.7	6.7	85.07%
State Wide	Muni/6.2	IOU/5.9	105.08%

E. Los Angeles: LADWP v. SCE

The comparison in the chapter 1-2 for LADWP and SCE exhibits a combination of elements shown in the first four comparisons. Total costs for these two utilities are the highest muni and IOU costs in the table, and each component, except SCE's non-income taxes, is either the highest or second highest in its class. LADWP has slightly more access than does SCE to low-cost federal preference and hydro power, although SCE has significant amounts, and LADWP does not have the nuclear costs that have burdened SCE; hence, even adjustment of LADWP's high energy-supply costs does not raise them to the level of SCE's supply costs.

Rate Comparison (Cents Per KWhr)[5]			
	LADWP	So Cal Edison	LADWP as Percent of So Cal Edison
Residential	10.0	12.3	81.30%
Commercial	9.7	12.0	80.83%
Industrial	8.2	6.6	124.24%
Total	9.3	10.4	89.42%
State Wide	IOU/10.0	Muni/8.6	116.28%

[5] From 1994 EIA form 861.

LADWP's T&D costs are at a relatively high level. SCE's T&D costs, similar to LADWP's, even with a much lower population density, are also at a level reached only by PG&E's. Just as the SMUD/PG&E comparison showed that inefficiencies in muni operation can push the adjusted totals higher than neighboring IOU costs, this one shows the sale result and here with a substantial margin. This is notable because SCE's costs are so high in all non-income-tax categories. On the other hand, the costs for SCE and LADWP are only slightly above muni and IOU averages in the state, as section I.A showed.

F. Seattle: SCWLP v. Puget

The Table 1-2 comparison for the Seattle City Water, Light and Power (SCWLP, the muni) utility and Puget South Power and Light Co. (Puget, the IOU) shows, above all, the effect of low-cost federal preference and hydro power, as these two utilities exhibit by far the lowest total costs in each class (muni and IOU) in the table. T&D costs for the two utilities are in the mainstream for each class, as well as very similar to each other when the SCWLP T&D costs are adjusted to reflect Puget's cost of capital and income-tax burden -- although SCWLP benefits here from a much higher population density in its service area. The remarkable feature of this comparison is the extremely low energy-supply cost exhibited by each of these two Pacific-Northwest utilities. SCWLP's energy-supply costs are so low that, even after adjustment for Puget's cost of capital and income taxes, the muni has a much lower component cost here -- despite the fact that this component for Puget is one of the lowest among all IOU electric utilities in the U.S. Neither of these utilities has any nuclear capacity. The fact that these figures are representative for those of munis and IOUs in Washington demonstrates also the effect of cheap hydro and preference power on such comparisons, for all utilities in that state reap that benefit. Finally, this comparison shows that a muni very efficient in all areas can sometimes serve at costs lower than those of an efficient IOU.

Rate Comparison
(Cents Per KWhr)

	Seattle	Puget	Seattle as Percent of Puget
Residential	3.8	6.0	63.33%
Commercial	3.7	6.0	61.67%
Industrial	3.3	4.4	75.00%
Total	3.8	5.7	66.67%

Customer Service 306,987,073

SACRAMENTO 95

Item	Source	Total	Reconciliation	Taxes	Production	Transmission	Distribution	General	
Revenues	SCHEDULE 2, LINE	613,986							
Operation & Maintenance	SCHEDULE 2, LINE	428,520	428,520		307,538	22,354	27,523		
Depreciation Expense	SCHEDULE 2, LINE	54,356	54,356		16,751	4,897	23,746	8,962	
General Taxes Property Taxes	SCHEDULE 4, LINE	146							
Amortization	SCHEDULE 4, LINE	64,066			64,066				
Pre-tax Income	Rev-O&M-Dep-Tax	66,898							
Gross Plant Gross Plant Percent	SCHEDULE 3, LINE	1,635,313	1,635,313		503,965 30.82%	147,320 9.01%	714,414 43.69%	269,613 16.49%	
Accumulated Depreciation	SCHEDULE 1, LINE	480,310			148,020	43,269	209,832	79,188	
Net Nuclear Fuel	SCHEDULE 1, LINE --			--					
Deferred Costs on Gen Plt	SCHEDULE 1, LINE	1,187,606			1,187,606				
Total Net Plant		2,342,609			1,543,551	104,050	504,583	190,425	
Rate of Return on Net Plant	Income/Net Plt	2.86%	17.53%		17.53%	17.53%	17.53%	17.53%	
Pre-tax Return	Net Plt x ROR	66,898			270,606	18,241	88,460	33,384	
Non-Fuel O&M Percent of Total	Total less Fuel	925,905 100.00%			64,171 6.93%	147319.722 15.91%	714414.106 77.16%		
Alloc Admin & Genl	Depr,O&M,Cap	78,462			5,438	12,484	95,530		
Total Cost to Serve		613,986	343,794 957,781	146.2	664,399	57,976	235,259		
Less: Sales for resale	SCHEDULE 5, LINE	(992)			(992)				
Net cost to serve		612,994			663,407				
Retail sales	SCHEDULE 8, LINE	8,459			8,459	8,459	8,459		
Retail cost/mwh		72.47	113.11	0.02	78.43	6.85	27.81		
Alternate Cost to Serve					657,969	45,492	139,729	78,462	34,990
Alternate Cost/mwh		113.11		0.02	77.78	5.38	16.52	9.28	4.14
Less: Other supply cost					(230,517)				
Net generation	SCHEDULE 8, LINE	3,608			3,608				
Production cost	Cost - Other + S/R				432,891				
Production cost/MWH					119.98				
Retail Production Cost/MWH Generated					74.50				

Total Losses	509
Total Purchases	5,533
Total Output	9,649
LOSS PERCENT	5.27%
Retail Sales	8,459
Employees	2,340
Salse/Res & Other	

PACIFIC GAS & ELECTRIC 1995

Item	Source	Total	Reconciliation	Taxes	Production	Transmission	Distribution	General	
Revenues	Page 114	7,406,799,572							
Operation & Maintenance	Page 320-322	3,823,194,121	3,823,194,121		2,587,084,498	74,250,956	281,930,265		
Depreciation Expense	Page 336	1,006,078,047	1,006,078,047		513,594,070	63,093,969	305,269,611	124,120,397	
General Taxes	Page 114	221,622,851		221,622,851					
Property Taxes	Page 262	199,644,848							
Amortization	Page 114	24,049,121			24,049,121				
Pre-tax Income	Rev-O&M-Dep-Tax	2,331,855,432							
Gross Plant	Page 204	22,523,667,523	22,572,634,161		10,960,236,481	2,188,968,132	8,768,812,747	605,650,163	
Accumulated Depreciation	Page 219	9,745,862,386			4,993,485,472	969,222,835	3,587,138,570	196,015,509	
Net Nuclear Fuel	Page 110	140,764,035			140,764,035				
Deferred Costs on Gen Plt	Page 232	382,445,000			382,445,000				
Total Net Plant		13,301,014,172			6,489,960,044	1,219,745,297	5,181,674,177	409,634,654	
Rate of Return on Net Plant	Income/Net Plt	17.53%			17.53%	17.53%	17.53%	17.53%	
Pre-tax Return	Net Plt x ROR	2,260,040,698			1,137,781,555	213,838,558	908,420,585		
Salaries excl A&G	Page 354	433,460,285			178,885,712	33,938,020	220,636,553		
Percent of Total		100.00%			41.27%	7.83%	50.90%		
Alloc Admin & Genl	Depr,O&M,Cap	768,876,460	0		317,309,377	60,199,621	698,354,535		
Total Cost to Serve		7,406,799,572	7,406,799,572	221,622,851	4,579,818,621	411,383,104	2,193,974,996	298,847,645	
		0	0.00%						
Less: Sales for resale	Page 301	162,707,302	(133,565,915)		162,707,302				
Net cost to serve		7,569,506,874		221,622,851	4,742,525,923	411,383,104	2,193,974,996		
Retail sales	Page 301	72,321,927		72,321,927	72,321,927	72,321,927	72,321,927	72,321,927	
Retail cost/mwh		104.66		3.06	65.58	5.69	30.34		
Net Cost w/o Admin	0	7,569,506,874		221,622,851	4,425,216,546	351,183,483	1,495,620,461	768,876,460	306,987,073
Retail Cost/MWH		104.66		3.06	61.19	4.86	20.68	10.63	4.24
		0							
Less: Other supply cost	Page 321				(1,739,460,462)				
Net generation	Page 401				49,671,252				
Production cost	Cost - Other + S/R				2,840,358,159		4742525922.5		
Production cost/MWH					57.18		2169657810		
Retail Production Cost/MWH Generated					61.33		2,572,868,113		
				Total Losses	6,010,034				
				Total Purchases	31,089,474				
				Total Output	86,770,760				
Net Income									
				LOSS PERCENT	6.93%				
BOY Common									
EOY Common				Retail Revenues	7,569,506,874				
Avg Common				Employees	15,072				

ROE

Sales/Res & Other 162,707,302

ACCUMULATED DEPRECIATION	PAGE 219	DEPRECIATION EXPENSE	PAGE 336	OTHER EXPENSES	
Nuclear	1,577,855,469	Nuclear	139,064,244	Cust Acct	174,727,248
Steam	2,576,327,370	Steam	326,884,438	Cust Service	121,616,849
Hydro	528,683,002	Hydro	26,396,614	Sales	10,642,976
Pumped Storage	263,464,459	Pumped Storage	18,398,280	Admin & Gen	572,941,329
Other	47,155,172	Other	2,850,494		
Total Production	4,993,485,472	Total Production	513,594,070	Total	879,928,402

SACRAMENTO 95

Pacific Gas and Electric		TOTAL RETAIL RATE		NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION	ADMIN & GENERAL	CUSTOMER SERVIC
Retail cost/mwh		104.66		3.06	65.58	5.69	30.34		
Net Cost w/o Admin	0	7,569,506,874		221,622,851	4,425,216,546	351,183,483	1,495,620,461	768,876,460	306,987,073
Retail Cost/MWH		104.66		3.06	61.19	4.86	20.68	10.63	4.24
SACRAMENTO 95	Actual without Cost of Capital Adjustment								
Retail cost/mwh		72.47	72.47	0.02	51.42	4.52	16.51		
Alternate Cost to Serve					431,442	30,222	65,678	50,516	34,990
Alternate Cost/mwh		72.47		0.02	51.00	3.57	7.76	5.97	4.14
SACRAMENTO 95	with Cost of Capital Adjustment								
Retail cost/mwh		72.47	113.11	0.02	78.43	6.85	27.81		
Alternate Cost to Serve					657,969	45,492	139,729	78,462	34,990
Alternate Cost/mwh		113.11		0.02	77.78	5.38	16.52	9.28	4.14
COST OF SERVICE WITH A&G ALLOCATION		TOTAL RETAIL RATE		NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION		
Pacific Gas and Electric		104.66		3.06	65.58	5.69	30.34		
SACRAMENTO 95		72.47		0.02	51.42	4.52	16.51		
SACRAMENTO 95	Adjusted	113.11		0.02	78.43	6.85	27.81		
MUNI AS PERCENT OF IOU WITH ALLOCATION									
Without Cost of Capital Adjustment		69.24%		0.56%	77.78%	62.81%	25.59%		
With Cost of Capital Adjustment		108.07%		0.56%	119.60%	120.49%	91.68%		
COST OF SERVICE WITHOUT A&G ALLOCATION		TOTAL RETAIL RATE		NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION	ADMIN & GENERAL	CUSTOMER SERVIC
Pacific Gas and Electric		104.66		3.06	61.19	4.86	20.68	10.63	4.24
SACRAMENTO 95		72.47		0.02	51.00	3.57	7.76	5.97	4.14
SACRAMENTO 95	Adjusted	113.11		0.02	77.78	5.38	16.52	9.28	4.14
MUNI AS PERCENT OF IOU WITHOUT ALLOCATION									
Without Cost of Capital Adjustment		69.24%		0.56%	83.36%	73.58%	37.55%	56.17%	97.45%
With Cost of Capital Adjustment		108.07%		0.56%	127.12%	110.75%	79.88%	87.25%	97.45%
Pacific Gas and Electric	Customers	4387.019		4387.019	4387.019	4387.019	4387.019	4387.019	4387.019
SACRAMENTO 95	Customers	479.82		479.82	479.82	479.82	479.82	479.82	479.82
Pacific Gas and Electric	Cost/Customer	1,725.43		50.52	1,008.71	80.05	340.92	175.26	69.98
SACRAMENTO 95	Cost/Customer	1,277.55		0.30	899.17	62.99	136.88	105.28	72.92
SACRAMENTO 95	Adj Cost/Customer	1,994.06		0.30	1,371.28	94.81	291.21	163.52	72.92
Muni/IOU at actual cost of capital							40.15%	60.07%	104.21%
OPERATION AND MAINTENANCE COSTS									
Pacific Gas and Electric	Cost/kWhr	52.86		0.00	35.77	1.03	3.90	7.92	4.24

SACRAMENTO 95	Cost/kWhr	50.66		36.36	2.64	3.25	4.27	4.14
Muni/IOU Ratio		95.83%		101.64%	257.40%	83.46%	53.89%	97.45%
Pacific Gas and Electric	Cost/Customer					64,264.66	130,599.24	69,976.24
SACRAMENTO 95	Cost/Customer					57,360.10	75,270.21	72,923.45
						89.26%	57.63%	104.21%

CLEVELAND 95

Item	Source	Total	Reconciliation	Taxes	Production	Transmission	Distribution	General	
Revenues	SCHEDULE 2, LINE	90,724							
Operation & Maintenance	SCHEDULE 2, LINE	71,316	71,316		44,929	890	17,365		
Depreciation Expense	SCHEDULE 2, LINE	5,885	5,885		1,100	1,937	2,456	393	
General Taxes Property Taxes	SCHEDULE 4, LINE	0							
Amortization	SCHEDULE 4, LINE --								
Pre-tax Income	Rev-O&M-Dep-Tax	13,523							
Gross Plant Gross Plant Percent	SCHEDULE 3, LINE	233,102	233,102		43,565 18.69%	76,704 32.91%	97,275 41.73%	15,558 6.67%	
Accumulated Depreciation	SCHEDULE 1, LINE	101,002			18,877	33,235	42,149	6,741	
Net Nuclear Fuel	SCHEDULE 1, LINE --			--					
Deferred Costs on Gen Plt	SCHEDULE 1, LINE	3,259			3,259				
Total Net Plant		135,360			27,948	43,469	55,126	8,817	
Rate of Return on Net Plant	Income/Net Plt	9.99%	9.57%		9.57%	9.57%	9.57%	9.57%	
Pre-tax Return	Net Plt x ROR	13,523			2,676	4,162	5,278	844	
Non-Fuel O&M Percent of Total	Total less Fuel	175,943 100.00%			1,964 1.12%	76703.943 43.60%	97274.771 55.29%		
Alloc Admin & Genl	Depr,O&M,Cap	7,123			80	3,105	6,184		
Total Cost to Serve		90,724	(563) 90,161	0	48,785	10,094	31,283		
Less: Sales for resale	SCHEDULE 5, LINE	0			0				
Net cost to serve		90,724			48,785				
Retail sales	SCHEDULE 8, LINE	1,148			1,148	1,148	1,148		
Retail cost/mwh		79.02	78.53	0.00	42.49	8.79	27.25		
Alternate Cost to Serve					48,705	6,988	25,099	7,123	2,246
Alternate Cost/mwh		78.53		0.00	42.42	6.09	21.86	6.20	1.96
Less: Other supply cost					(42,965)				
Net generation	SCHEDULE 8, LINE	11			11				
Production cost	Cost - Other + S/R				5,820				
Production cost/MWH					523.86				
Retail Production Cost/MWH Generated					39.42				

Total Losses	115
Total Purchases	1,353
Total Output	1,479
LOSS PERCENT	7.80%
Retail Sales	1,148
Employees	0
Sales/Res & Other	

CLEVELAND ELECTRIC 1995

Item	Source	Total	Reconciliation	Taxes	Production	Transmission	Distribution	General	
Revenues	Page 114	1,768,736,560							
Operation & Maintenance	Page 320-322	886,901,242	886,901,242		686,144,005	19,183,071	52,188,494		
Depreciation Expense	Page 336	196,980,175	196,980,175		136,863,827	15,502,291	37,764,217	6,849,840	
General Taxes	Page 114	229,962,334		229,962,334					
Property Taxes	Page 262	132,000,000							
Amortization	Page 114	(23,157,737)			(23,157,737)				
Pre-tax Income	Rev-O&M-Dep-Tax	478,050,546							
Gross Plant	Page 204	6,552,821,569	22,572,634,161		4,745,239,010	636,655,806	1,027,724,031	143,202,722	
Accumulated Depreciation	Page 219	2,237,908,321			1,616,451,174	228,775,340	357,551,070	35,130,737	
Net Nuclear Fuel	Page 110	121,966,058			121,966,058				
Deferred Costs on Gen Plt	Page 232	555,895,220			555,895,220				
Total Net Plant		4,992,774,526			3,806,649,114	407,880,466	670,172,961	108,071,985	
Rate of Return on Net Plant	Income/Net Plt	9.57%			9.57%	9.57%	9.57%	9.57%	
Pre-tax Return	Net Plt x ROR	467,702,818			364,480,847	39,053,933	64,168,039		
Salaries excl A&G	Page 354	72,670,258			42,007,768	5,842,397	24,820,093		
Percent of Total		100.00%			57.81%	8.04%	34.15%		
Alloc Admin & Genl	Depr,O&M,Cap	99,813,122			57,697,971	8,024,574	80,860,694		
Total Cost to Serve		1,768,736,560	1,768,736,560	229,962,334	1,222,028,913	81,763,869	234,981,444	35,149,070	
		0	0.00%						
Less: Sales for resale	Page 301	(82,760,416)	(30,767,434)		(82,760,416)				
Net cost to serve		1,685,976,144		229,962,334	1,139,268,497	81,763,869	234,981,444		
Retail sales	Page 301	19,553,088		19,553,088	19,553,088	19,553,088	19,553,088	19,553,088	
Retail cost/mwh		86.23		11.76	58.27	4.18	12.02		
Net Cost w/o Admin	(0)	1,685,976,144		229,962,334	1,081,570,526	73,739,295	154,120,750	99,813,122	46,770,118
Retail Cost/MWH		86.23		11.76	55.31	3.77	7.88	5.10	2.39
		(0)							
Less: Other supply cost	Page 321				(141,768,583)				
Net generation	Page 401				20,906,746				
Production cost	Cost - Other + S/R				1,080,260,330		1139268497.2		
Production cost/MWH					51.67		586592640		
Retail Production Cost/MWH Generated					54.99		552,675,857		
				Total Losses	1,432,608				
				Total Purchases	1,704,864				
				Total Output	24,044,218				
Net Income									
BOY Common				LOSS PERCENT	5.96%				
EOY Common				Retail Revenues	1,685,976,144				
Avg Common				Employees	3,636				

ROE

ACCUMULATED DEPRECIATION	PAGE 219
Nuclear	541,950,788
Steam	817,065,139
Hydro	21,774,677
Pumped Storage	6,885,230
Other	228,775,340
Total Production	1,616,451,174

ACCUMULATED DEPRECIATION	PAGE 219

DEPRECIATION EXPENSE	PAGE 336
Nuclear	36,402,324
Steam	98,861,425
Hydro	0
Pumped Storage	1,250,478
Other	349,600
Total Production	136,863,827

DEPRECIATION EXPENSE	PAGE 336

Salse/Res & Other (82,760,416)

OTHER EXPENSES	
Cust Acct	28,299,230
Cust Service	15,901,463
Sales	2,569,425
Admin & Gen	82,615,554
Total	129,385,672
Total w/o A&G	46,770,118

CLEVELAND 95

Cleveland Electric Illuminating		TOTAL RETAIL RATE		NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION	ADMIN & GENERAL	CUSTOMER SERVIC
Retail cost/mwh		86.23		11.76	58.27	4.18	12.02		
Net Cost w/o Admin	(0)	1,685,976,144		229,962,334	1,081,570,526	73,739,295	154,120,750	99,813,122	46,770,118
Retail Cost/MWH		86.23		11.76	55.31	3.77	7.88	5.10	2.39
CLEVELAND 95	Actual without Cost of Capital Adjustment								
Retail cost/mwh		79.02	79.02	0.00	42.59	8.96	27.46		
Alternate Cost to Serve					48,821	7,169	25,328	7,160	2,246
Alternate Cost/mwh		79.02		0.00	42.52	6.24	22.06	6.24	1.96
CLEVELAND 95	with Cost of Capital Adjustment								
Retail cost/mwh		79.02	78.53	0.00	42.49	8.79	27.25		
Alternate Cost to Serve					48,705	6,988	25,099	7,123	2,246
Alternate Cost/mwh		78.53		0.00	42.42	6.09	21.86	6.20	1.96
COST OF SERVICE WITH A&G ALLOCATION		TOTAL RETAIL RATE		NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION		
Cleveland Electric Illuminating		86.23		11.76	58.27	4.18	12.02		
CLEVELAND 95		79.02		0.00	42.59	8.96	27.46		
CLEVELAND 95	Adjusted	78.53		0.00	42.49	8.79	27.25		
MUNI AS PERCENT OF IOU WITH ALLOCATION									
Without Cost of Capital Adjustment		91.64%		0.00%	72.98%	149.33%	183.57%		
With Cost of Capital Adjustment		91.08%		0.00%	72.93%	210.25%	226.73%		
COST OF SERVICE WITHOUT A&G ALLOCATION		TOTAL RETAIL RATE		NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION	ADMIN & GENERAL	CUSTOMER SERVIC
Cleveland Electric Illuminating		86.23		11.76	55.31	3.77	7.88	5.10	2.39
CLEVELAND 95		79.02		0.00	42.52	6.24	22.06	6.24	1.96
CLEVELAND 95	Adjusted	78.53		0.00	42.42	6.09	21.86	6.20	1.96
MUNI AS PERCENT OF IOU WITHOUT ALLOCATION									
Without Cost of Capital Adjustment		91.64%		0.00%	76.88%	165.58%	279.88%	122.16%	81.78%
With Cost of Capital Adjustment		91.08%		0.00%	76.69%	161.40%	277.35%	121.54%	81.78%
Cleveland Electric Illuminating	Customers	668.905		668.905	668.905	668.905	668.905	668.905	668.905
CLEVELAND 95	Customers	66.636		66.636	66.636	66.636	66.636	66.636	66.636
Cleveland Electric Illuminating	Cost/Customer	2,520.50		343.79	1,616.93	110.24	230.41	149.22	69.92
CLEVELAND 95	Cost/Customer	1,361.49		0.00	732.66	107.59	380.10	107.45	33.70
CLEVELAND 95	Adj Cost/Customer	1,353.04		0.00	730.91	104.88	376.66	106.90	33.70
Muni/IOU at actual cost of capital							164.97%	72.01%	48.20%
							163.47%	71.64%	48.20%
OPERATION AND MAINTENANCE COSTS									
Cleveland Electric Illuminating	Cost/kWhr	45.36		0.00	35.09	0.98	2.67	6.62	2.39

CLEVELAND 95	Cost/kWhr	62.12	39.13	0.78	15.12	5.13	1.96
Muni/IOU Ratio		136.94%	111.52%	79.00%	566.66%	77.48%	81.78%
Cleveland Electric Illuminating	Cost/Customer				78,020.79	193,429.07	69,920.42
CLEVELAND 95	Cost/Customer				260,589.25	88,332.49	33,702.56
					334.00%	45.67%	48.20%

JACKSONVILLE 95

Total Cust Serv 202,044,371

Item	Source	Total	Reconciliation	Taxes	Production	Transmission	Distribution	General	
Revenues	SCHEDULE 2, LINE	739,386							
Operation & Maintenance	SCHEDULE 2, LINE	423,356	423,356		341,716	8,161	21,388		
Depreciation Expense	SCHEDULE 2, LINE	114,906	114,906		75,115	10,630	24,773	4,387	
General Taxes Property Taxes	SCHEDULE 4, LINE	64,118							
Amortization	SCHEDULE 4, LINE --				--				
Pre-tax Income	Rev-O&M-Dep-Tax	137,006							
Gross Plant Gross Plant Percent	SCHEDULE 3, LINE	2,981,615	2,981,615		1,949,126 65.37%	275,834 9.25%	642,832 21.56%	113,823 3.82%	
Accumulated Depreciation Net Nuclear Fuel Deferred Costs on Gen Plt	SCHEDULE 1, LINE SCHEDULE 1, LINE -- SCHEDULE 1, LINE	765,464 405,746			500,395 -- 405,746	70,814	165,033	29,222	
Total Net Plant		2,621,898			1,854,477	205,020	477,799	84,602	
Rate of Return on Net Plant	Income/Net Plt	5.23%	12.54%		12.54%	12.54%	12.54%	12.54%	
Pre-tax Return	Net Plt x ROR	137,006			232,534	25,708	59,912	10,608	
Non-Fuel O&M Percent of Total	Total less Fuel	988,045 100.00%			69,379 7.02%	275833.715 27.92%	642832.319 65.06%		
Alloc Admin & Genl	Depr,O&M,Cap	55,845			3,921	15,590	47,575		
Total Cost to Serve		739,386	191,756 931,141	64118.042	653,287	60,089	153,648		
Less: Sales for resale	SCHEDULE 5, LINE	(109,544)			(109,544)				
Net cost to serve		629,842			543,743				
Retail sales	SCHEDULE 8, LINE	9,269			9,269	9,269	9,269		
Retail cost/mwh		67.95	88.64	6.92	58.66	6.48	16.58		
Alternate Cost to Serve					539,821	44,498	106,073	55,845	11,242
Alternate Cost/mwh		88.64		6.92	58.24	4.80	11.44	6.02	1.21
Less: Other supply cost					(75,408)				
Net generation	SCHEDULE 8, LINE	3,432			3,432				
Production cost	Cost - Other + S/R				468,334				
Production cost/MWH					136.44				
Retail Production Cost/MWH Generated					54.63				

Total Losses	463
Total Purchases	2,380
Total Output	6,275
LOSS PERCENT	7.38%
Retail Sales	9,269
Employees	2
Sales/Res & Other	

FP&L 1995

Item	Source	Total	Reconciliation		Taxes	Production	Transmission	Distribution	General	
Revenues	Page 114	5,530,057,167								
Operation & Maintenance	Page 320-322	2,860,324,561	2,860,324,561			2,145,658,876	40,130,204	182,401,698		
Depreciation Expense	Page 336	841,222,401	841,222,401			568,976,642	38,280,227	183,504,730	50,460,802	
General Taxes	Page 114	547,976,007			547,976,007					
Property Taxes	Page 262	171,852								
Amortization	Page 114	111,386,541				111,386,541				
Pre-tax Income	Rev-O&M-Dep-Tax	1,169,147,657								
Gross Plant	Page 204	15,700,829,995	22,572,634,161			7,681,246,310	1,981,453,497	5,151,736,671	886,393,517	
Accumulated Depreciation	Page 219	6,636,608,848				3,798,844,941	838,938,390	1,797,565,123	201,260,394	
Net Nuclear Fuel	Page 110	179,100,119				179,100,119				
Deferred Costs on Gen Plt	Page 232	80,713,312				80,713,312				
Total Net Plant		9,324,034,578				4,142,214,800	1,142,515,107	3,354,171,548	685,133,123	
Rate of Return on Net Plant	Income/Net Plt	12.54%				12.54%	12.54%	12.54%	12.54%	
Pre-tax Return	Net Plt x ROR	1,083,238,303				519,395,406	143,260,822	420,582,075		
Salaries excl A&G	Page 354	402,934,258				212,349,753	13,380,653	177,203,852		
Percent of Total		100.00%				52.70%	3.32%	43.98%		
Alloc Admin & Genl	Depr,O&M,Cap	426,459,568				224,747,790	14,161,882	389,594,267		
Total Cost to Serve		5,530,057,167	5,530,057,167	0	547,976,007	3,570,165,255	235,833,135	1,176,082,769	164,038,419	
		0	0.00%							
Less: Sales for resale	Page 301	(204,798,244)	(115,962,285)			(204,798,244)				
Net cost to serve		5,325,258,923			547,976,007	3,365,367,011	235,833,135	1,176,082,769		
Retail sales	Page 301	76,246,931			76,246,931	76,246,931	76,246,931	76,246,931	76,246,931	
Retail cost/mwh		69.84			7.19	44.14	3.09	15.42		
Net Cost w/o Admin	0	5,325,258,923			547,976,007	3,140,619,221	221,671,253	786,488,503	426,459,568	202,044,371
Retail Cost/MWH		69.84			7.19	41.19	2.91	10.32	5.59	2.65
Less: Other supply cost	Page 321					(587,874,106)				
Net generation	Page 401					68,653,279				
Production cost	Cost - Other + S/R					2,982,291,149		3365367011		
Production cost/MWH						43.44		2287407930		
Retail Production Cost/MWH Generated						42.49		1,077,959,081		
					Total Losses	5,521,865				
					Total Purchases	68,653,279				
					Total Output	142,828,423				
Net Income										
BOY Common					LOSS PERCENT	3.87%				
EOY Common					Retail Revenues	5,325,258,923				
Avg Common					Employees	11,243				

ROE

Salse/Res & Other (204,798,244)

ACCUMULATED DEPRECIATION	PAGE 219
Nuclear	1,358,582,005
Steam	2,111,647,106
Hydro	0
Pumped Storage	0
Other	328,615,830
Total Production	3,798,844,941

DEPRECIATION EXPENSE	PAGE 336
Nuclear	139,782,752
Steam	371,507,606
Hydro	0
Pumped Storage	0
Other	57,686,284
Total Production	568,976,642

OTHER EXPENSES	
Cust Acct	113,577,617
Cust Service	88,230,058
Sales	236,696
Admin & Gen	290,089,412
Total	492,133,783

JACKSONVILLE 95

Florida Power & Light		TOTAL RETAIL RATE		NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION	ADMIN & GENERAL	CUSTOMER SERVIC
Retail cost/mwh		69.84		7.19	44.14	3.09	15.42		
Net Cost w/o Admin	0	5,325,258,923		547,976,007	3,140,619,221	221,671,253	786,488,503	426,459,568	202,044,371
Retail Cost/MWH		69.84		7.19	41.19	2.91	10.32	5.59	2.65
JACKSONVILLE 95	Actual without Cost of Capital Adjustment								
Retail cost/mwh		67.95	67.95	6.92	43.98	4.68	12.37		
Alternate Cost to Serve					404,192	29,504	71,129	49,657	11,242
Alternate Cost/mwh		67.95		6.92	43.61	3.18	7.67	5.36	1.21
JACKSONVILLE 95	with Cost of Capital Adjustment								
Retail cost/mwh		67.95	88.64	6.92	58.66	6.48	16.58		
Alternate Cost to Serve					539,821	44,498	106,073	55,845	11,242
Alternate Cost/mwh		88.64		6.92	58.24	4.80	11.44	6.02	1.21

COST OF SERVICE WITH A&G ALLOCATION		TOTAL RETAIL RATE	NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION
Florida Power & Light		69.84	7.19	44.14	3.09	15.42
JACKSONVILLE 95		67.95	6.92	43.98	4.68	12.37
JACKSONVILLE 95	Adjusted	88.64	6.92	58.66	6.48	16.58
MUNI AS PERCENT OF IOU WITH ALLOCATION						
Without Cost of Capital Adjustment		97.29%	96.25%	98.80%	102.91%	49.75%
With Cost of Capital Adjustment		126.92%	96.25%	132.91%	209.60%	107.47%

COST OF SERVICE WITHOUT A&G ALLOCATION		TOTAL RETAIL RATE	NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION	ADMIN & GENERAL	CUSTOMER SERVIC
Florida Power & Light		69.84	7.19	41.19	2.91	10.32	5.59	2.65
JACKSONVILLE 95		67.95	6.92	43.61	3.18	7.67	5.36	1.21
JACKSONVILLE 95	Adjusted	88.64	6.92	58.24	4.80	11.44	6.02	1.21
MUNI AS PERCENT OF IOU WITHOUT ALLOCATION								
Without Cost of Capital Adjustment		97.29%	96.25%	105.87%	109.49%	74.40%	95.79%	45.77%
With Cost of Capital Adjustment		126.92%	96.25%	141.39%	165.13%	110.95%	107.72%	45.77%
Florida Power & Light	Customers	3097.194	3097.194	3097.194	3097.194	3097.194	3097.194	3097.194
JACKSONVILLE 95	Customers	313.051	313.051	313.051	313.051	313.051	313.051	313.051
Florida Power & Light	Cost/Customer	1,719.38	176.93	1,014.02	71.57	253.94	137.69	65.23
JACKSONVILLE 95	Cost/Customer	2,011.95	204.82	1,291.14	94.25	227.21	158.62	35.91
JACKSONVILLE 95	Adj Cost/Customer	2,624.48	204.82	1,724.39	142.14	338.84	178.39	35.91
Muni/IOU at actual cost of capital						89.48%	115.20%	55.05%
						133.43%	129.56%	55.05%

OPERATION AND MAINTENANCE COSTS

Florida Power & Light	Cost/kWhr	37.51	0.00	28.14	0.53	2.39	3.80	2.65
JACKSONVILLE 95	Cost/kWhr	45.68		36.87	0.88	2.31	4.41	1.21
Muni/IOU Ratio		121.76%		131.01%	167.28%	96.46%	115.84%	45.77%
Florida Power & Light	Cost/Customer					58,892.56	93,662.01	65,234.65
JACKSONVILLE 95	Cost/Customer					68,320.69 116.01%	130,489.09 139.32%	35,911.24 55.05%

SAN ANTONIO 95

Total w/o A&G 167,977,337

Item	Source	Total	Reconciliation	Taxes	Production	Transmission	Distribution	General	
Revenues	SCHEDULE 2, LINE	775,987							
Operation & Maintenance	SCHEDULE 2, LINE	358,228	358,228		244,948	3,718	30,864		
Depreciation Expense	SCHEDULE 2, LINE	141,507	141,507		103,046	7,242	25,590	5,629	
General Taxes Property Taxes	SCHEDULE 4, LINE	95,109							
Amortization	SCHEDULE 4, LINE --				--				
Pre-tax Income	Rev-O&M-Dep-Tax	181,143							
Gross Plant Gross Plant Percent	SCHEDULE 3, LINE	4,546,723	4,546,723		3,310,956 72.82%	232,699 5.12%	822,218 18.08%	180,850 3.98%	
Accumulated Depreciation	SCHEDULE 1, LINE	1,269,710			924,612	64,983	229,611	50,504	
Net Nuclear Fuel	SCHEDULE 1, LINE	176527.479			176,527				
Deferred Costs on Gen Plt	SCHEDULE 1, LINE	27,673			27,673				
Total Net Plant		3,481,213			2,590,544	167,716	592,607	130,346	
Rate of Return on Net Plant	Income/Net Plt	5.20%	10.06%		10.06%	10.06%	10.06%	10.06%	
Pre-tax Return	Net Plt x ROR	181,143			260,679	16,877	59,632	13,116	
Non-Fuel O&M Percent of Total	Total less Fuel	1,295,197 100.00%			240,281 18.55%	232698.922 17.97%	822217.896 63.48%		
Alloc Admin & Gen1	Depr,O&M,Cap	86,849	169,162		16,112	15,604	65,727		
Total Cost to Serve		775,987	945,149	95109.07%	624,785	43,441	181,814		
Less: Sales for resale	SCHEDULE 5, LINE	(15,546)			(15,546)				
Net cost to serve		760,441			609,239				
Retail sales	SCHEDULE 8, LINE	13,647			13,647	13,647	13,647		
Retail cost/mwh		55.72	68.12	6.97	44.64	3.18	13.32		
Alternate Cost to Serve					593,127	27,837	116,087	86,849	10,593
Alternate Cost/mwh		68.12		6.97	43.46	2.04	8.51	6.36	0.78
Less: Other supply cost					(4,667)				
Net generation	SCHEDULE 8, LINE	14,765			14,765				
Production cost	Cost - Other + S/R				604,572				
Production cost/MWH					40.95				
Retail Production Cost/MWH Generated					42.44				

Total Losses	814
Total Purchases	126
Total Output	15,704
LOSS PERCENT	5.18%
Retail Sales	13,647
Employees	3
Sales/Res & Other	

TEXAS UTILITIES 1995

Item	Source	Total	Reconciliation	Taxes	Production	Transmission	Distribution	General	
Revenues	Page 114	5,559,998,784							
Operation & Maintenance	Page 320-322	2,746,624,993	2,746,624,993		2,120,240,179	40,436,078	112,146,977		
Depreciation Expense	Page 336	538,674,477	538,674,477		370,920,854	31,291,229	126,253,752	10,208,642	
General Taxes	Page 114	512,045,173		512,045,173					
Property Taxes	Page 262	188,864,984							
Amortization	Page 114	10,996,801			10,996,801				
Pre-tax Income	Rev-O&M-Dep-Tax	1,751,657,340							
Gross Plant	Page 204	21,891,795,811	0		15,699,488,470	1,586,547,397	4,229,793,634	375,966,310	
Accumulated Depreciation	Page 219	5,046,538,647			3,061,889,236	581,563,396	1,302,254,987	100,831,028	
Net Nuclear Fuel	Page 110	562,125,240			562,125,240				
Deferred Costs on Gen Plt	Page 232	0			0				
Total Net Plant		17,407,382,404			13,199,724,474	1,004,984,001	2,927,538,647	275,135,282	
Rate of Return on Net Plant	Income/Net Plt	10.06%			10.06%	10.06%	10.06%	10.06%	
Pre-tax Return	Net Plt x ROR	1,723,971,228			1,328,252,216	101,128,795	294,590,217		
Salaries excl A&G	Page 354	274,254,683			152,949,005	15,973,503	105,332,175		
Percent of Total		100.00%			55.77%	5.82%	38.41%		
Alloc Admin & Genl	Depr,O&M,Cap	343,719,176			191,688,635	20,019,346	299,988,532		
			0						
Total Cost to Serve		5,559,998,784	5,559,998,784	512,045,173	4,022,098,686	192,875,447	832,979,478	130,537,615	
		0	0.00%						
Less: Sales for resale	Page 301	(109,554,816)	181,892,657		(109,554,816)				
Net cost to serve		5,450,443,968		512,045,173	3,912,543,870	192,875,447	832,979,478		
Retail sales	Page 301	85,220,681		85,220,681	85,220,681	85,220,681	85,220,681	85,220,681	
Retail cost/mwh		63.96		6.01	45.91	2.26	9.77		
Net Cost w/o Admin	0	5,450,443,968		512,045,173	3,720,855,234	172,856,102	532,990,946	343,719,176	167,977,337
Retail Cost/MWH		63.96		6.01	43.66	2.03	6.25	4.03	1.97
		0							
Less: Other supply cost	Page 321				(484,376,344)				
Net generation	Page 401				83,876,565				
Production cost	Cost - Other + S/R				3,537,722,342		39125[3869.9		
Production cost/MWH					42.18		2556620430		
Retail Production Cost/MWH Generated					43.51		1,355,923,440		

	Total Losses	5,514,386
	Total Purchases	10,700,246
	Total Output	100,091,197
Net Income		
	LOSS PERCENT	5.51%
BOY Common		
EOY Common	Retail Revenues	5,450,443,968
Avg Common	Employees	7,624

8

ROE

ACCUMULATED DEPRECIATION	PAGE 219
Nuclear	1,885,607,113
Steam	1,176,202,554
Hydro	0
Pumped Storage	0
Other	79,569
Total Production	3,061,889,236

DEPRECIATION EXPENSE	PAGE 336
Nuclear	80,693,518
Steam	290,211,106
Hydro	0
Pumped Storage	0
Other	16,230
Total Production	370,920,854

Salse/Res & Other (109,554,816)

OTHER EXPENSES	
Cust Acct	120,328,973
Cust Service	47,647,122
Sales	1,242
Admin & Gen	305,824,422
Total	473,801,759

SAN ANTONIO 95

TEXAS UTILITIES		TOTAL RETAIL RATE		NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION	ADMIN & GENERAL	CUSTOMER SERVIC
Retail cost/mwh		63.96		6.01	45.91	2.26	9.77		
Net Cost w/o Admin	0	5,450,443,968		512,045,173	3,720,855,234	172,856,102	532,990,946	343,719,176	167,977,337
Retail Cost/MWH		63.96		6.01	43.66	2.03	6.25	4.03	1.97
SAN ANTONIO 95	Actual without Cost of Capital Adjustment								
Retail cost/mwh		55.72	55.72	6.97	35.33	2.50	10.92		
Alternate Cost to Serve					467,245	19,687	87,290	80,516	10,593
Alternate Cost/mwh		55.72		6.97	34.24	1.44	6.40	5.90	0.78
SAN ANTONIO 95	with Cost of Capital Adjustment								
Retail cost/mwh		55.72	68.12	6.97	44.64	3.18	13.32		
Alternate Cost to Serve					593,127	27,837	116,087	86,849	10,593
Alternate Cost/mwh		68.12		6.97	43.46	2.04	8.51	6.36	0.78

COST OF SERVICE WITH A&G ALLOCATION		TOTAL RETAIL RATE	NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION
TEXAS UTILITIES		63.96	6.01	45.91	2.26	9.77
SAN ANTONIO 95		55.72	6.97	35.33	2.50	10.92
SAN ANTONIO 95	Adjusted	68.12	6.97	44.64	3.18	13.32
MUNI AS PERCENT OF IOU WITH ALLOCATION						
Without Cost of Capital Adjustment		87.13%	115.99%	74.58%	63.74%	65.44%
With Cost of Capital Adjustment		106.51%	115.99%	97.24%	140.65%	136.30%

CSOT OF SERVICE WITHOUT A&G ALLOCATION		TOTAL RETAIL RATE	NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION	ADMIN & GENERAL	CUSTOMER SERVIC
TEXAS UTILITIES		63.96	6.01	43.66	2.03	6.25	4.03	1.97
SAN ANTONIO 95		55.72	6.97	34.24	1.44	6.40	5.90	0.78
SAN ANTONIO 95	Adjusted	68.12	6.97	43.46	2.04	8.51	6.36	0.78
MUNI AS PERCENT OF IOU WITHOUT ALLOCATION								
Without Cost of Capital Adjustment		87.13%	115.99%	78.42%	71.12%	102.27%	146.28%	39.38%
With Cost of Capital Adjustment		106.51%	115.99%	99.54%	100.57%	136.01%	157.79%	39.38%
TEXAS UTILITIES	Customers	2005.26	2005.26	2005.26	2005.26	2005.26	2005.26	2005.26
SAN ANTONIO 95	Customers	501.981	501.981	501.981	501.981	501.981	501.981	501.981
TEXAS UTILITIES	Cost/Customer	2,710.07	255.35	1,855.55	86.20	265.80	171.41	83.77
SAN ANTONIO 95	Cost/Customer	1,514.88	189.47	930.80	39.22	173.89	160.40	21.10
SAN ANTONIO 95	Adj Cost/Customer	1,851.87	189.47	1,181.57	55.45	231.26	173.01	21.10
OPERATION AND MAINTENANCE COSTS								
TEXAS UTILITIES	Cost/kWhr	32.23	0.00	24.88	0.47	1.32	3.59	1.97
SAN ANTONIO 95	Cost/kWhr	26.25		17.95	0.27	2.26	4.99	0.78
Muni/IOU Ratio		81.45%		72.14%	57.42%	171.86%	139.06%	39.38%

TEXAS UTILITIES	Cost/Customer	55,926.40	152,511.11	83,768.36
SAN ANTONIO 95	Cost/Customer	61,485.34	135,671.54	21,103.01
		109.94%	88.96%	25.19%

LOS ANGELES 95

Item	Source	Total	Reconciliation	Taxes	Production	Transmission	Distribution	General	
Revenues	SCHEDULE 2, LINE	1,972,786							
Operation & Maintenance	SCHEDULE 2, LINE	1,496,634	1,496,634		1,010,146	35,620	127,611		
Depreciation Expense	SCHEDULE 2, LINE	203,758	203,758		70,101	22,586	88,221	22,848	
General Taxes Property Taxes	SCHEDULE 4, LINE	87,596							
Amortization	SCHEDULE 4, LINE --				--				
Pre-tax Income	Rev-O&M-Dep-Tax	184,799							
Gross Plant Gross Plant Percent	SCHEDULE 3, LINE	6,683,225	6,683,225		2,299,320 34.40%	740,823 11.08%	2,893,654 43.30%	749,427 11.21%	
Accumulated Depreciation Net Nuclear Fuel Deferred Costs on Gen Plt	SCHEDULE 1, LINE SCHEDULE 1, LINE SCHEDULE 1, LINE	2,209,090 76460.595 5,796			760,023 76,461 5,796	244,874	956,476	247,718	
Total Net Plant		4,556,392			1,621,554	495,950	1,937,178	501,710	
Rate of Return on Net Plant	Income/Net Plt	4.06%	16.69%		16.69%	16.69%	16.69%	16.69%	
Pre-tax Return	Net Plt x ROR	184,799			270,578	82,756	323,244	83,717	
Non-Fuel O&M Percent of Total	Total less Fuel	3,746,006 100.00%			111,529 2.98%	740823.401 19.78%	2893653.785 77.25%		
Alloc Admin & Genl	Depr,O&M,Cap	347,791			10,355	68,780	350,688		
Total Cost to Serve		1,972,786	575,496 2,548,282	87595.707	1,361,180	209,742	889,764		
Less: Sales for resale	SCHEDULE 5, LINE	(29,162)			(29,162)				
Net cost to serve		1,943,625			1,332,019				
Retail sales	SCHEDULE 8, LINE	20,513			20,513	20,513	20,513		
Retail cost/mwh		94.75	122.80	4.27	64.93	10.22	43.38		
Alternate Cost to Serve					1,321,664	140,962	539,076	347,791	82,032
Alternate Cost/mwh		122.80		4.27	64.43	6.87	26.28	16.95	4.00
Less: Other supply cost					(659,612)				
Net generation	SCHEDULE 8, LINE	13,181			13,181				
Production cost	Cost - Other + S/R				672,407				
Production cost/MWH					51.01				
Retail Production Cost/MWH Generated					62.23				

Total Losses	1,097
Total Purchases	10,930
Total Output	25,208
LOSS PERCENT	4.35%
Retail Sales	20,513
Employees	8
Salse/Res & Other	

SO CAL EDISON 1995

Item	Source	Total	Reconciliation		Taxes	Production	Transmission	Distribution	General	
Revenues	Page 114	7,863,569,329								
Operation & Maintenance	Page 320-322	4,777,261,829	4,777,261,829			3,639,717,323	81,035,454	177,175,592		
Depreciation Expense	Page 336	839,282,628	839,282,628			416,945,119	59,357,809	238,859,303	124,120,397	
General Taxes	Page 114	200,085,231			200,085,231					
Property Taxes	Page 262	149,064,167								
Amortization	Page 114	229,744,040				229,744,040				
Pre-tax Income	Rev-O&M-Dep-Tax	1,817,195,601								
Gross Plant	Page 204	18,989,371,591	22,572,634,161			9,079,919,365	2,830,673,831	6,473,128,232	605,650,163	
Accumulated Depreciation	Page 219	8,326,780,766				4,928,652,951	962,661,598	2,239,450,708	196,015,509	
Net Nuclear Fuel	Page 110	139,410,495				139,410,495				
Deferred Costs on Gen Plt	Page 232	88,315,093				88,315,093				
Total Net Plant		10,890,316,413				4,378,992,002	1,868,012,233	4,233,677,524	409,634,654	
Rate of Return on Net Plant	Income/Net Plt	16.69%				16.69%	16.69%	16.69%	16.69%	
Pre-tax Return	Net Plt x ROR	1,748,842,556				730,693,646	311,702,937	706,445,973		
Salaries excl A&G	Page 354	414,144				178,584	36,554	199,006		
Percent of Total		100.00%				43.12%	8.83%	48.05%		
Alloc Admin & Genl	Depr,O&M,Cap	837,805,082				361,271,883	73,948,016	636,587,003		
Total Cost to Serve		7,863,569,329	7,863,569,329	0	200,085,231	5,378,372,011	526,044,216	1,759,067,871	282,407,561	
		0	0.00%							
Less: Sales for resale	Page 301	(288,121,185)	(102,253,619)			(288,121,185)				
Net cost to serve		7,575,448,144			200,085,231	5,090,250,826	526,044,216	1,759,067,871		
Retail sales	Page 301	71,481,575			71,481,575	71,481,575	71,481,575	71,481,575	71,481,575	
Retail cost/mwh		105.98			2.80	71.21	7.36	24.61		
Net Cost w/o Admin	(0)	7,575,448,144			200,085,231	4,728,978,943	452,096,200	1,122,480,868	837,805,082	234,001,820
Retail Cost/MWH		105.98			2.80	66.16	6.32	15.70	11.72	3.27
		(0)								
Less: Other supply cost	Page 321					(2,581,906,313)				
Net generation	Page 401					48,567,901				
Production cost	Cost - Other + S/R					2,796,465,698		5090250826		
Production cost/MWH						57.58		2144447250		
Retail Production Cost/MWH Generated						65.09		2,945,803,576		
					Total Losses	8,596,113				
					Total Purchases	34,314,888				
					Total Output	91,478,902				
Net Income										
					LOSS PERCENT	9.40%				
BOY Common										
EOY Common					Retail Revenues	7,575,448,144				

Avg Common

Employees 16,660

ROE

ACCUMULATED DEPRECIATION	PAGE 219	DEPRECIATION EXPENSE	PAGE 336	OTHER EXPENSES	
Nuclear	1,575,443,932	Nuclear	65,067,601	Cust Acct	158,287,164
Steam	2,921,901,849	Steam	332,788,438	Cust Service	75,714,656
Hydro	182,520,678	Hydro	12,057,441	Sales	0
Pumped Storage	0	Pumped Storage	0	Admin & Gen	645,331,640
Other	248,786,492	Other	7,031,639		
Total Production	4,928,652,951	Total Production	416,945,119	Total	879,333,460
				Salse/Res & Other	(288,121,185)
				Total w/o A&G	234,001,820

Souther California Edison		TOTAL RETAIL RATE		NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION	ADMIN & GENERAL	CUSTOMER SERVICE
Retail cost/mwh		105.98		2.80	71.21	7.36	24.61		
Net Cost w/o Admin	(0)	7,575,448,144		200,085,231	4,728,978,943	452,096,200	1,122,480,868	837,805,082	234,001,820
Retail Cost/MWH		105.98		2.80	66.16	6.32	15.70	11.72	3.27
LOS ANGELES 95	Actual without Cost of Capital Adjustment								
Retail cost/mwh		94.75	94.75	4.27	54.86	6.56	29.06		
Alternate Cost to Serve					1,116,853	78,321	294,401	284,422	82,032
Alternate Cost/mwh		94.75		4.27	54.45	3.82	14.35	13.87	4.00
LOS ANGELES 95	with Cost of Capital Adjustment								
Retail cost/mwh		94.75	122.80	4.27	64.93	10.22	43.38		
Alternate Cost to Serve					1,321,664	140,962	539,076	347,791	82,032
Alternate Cost/mwh		122.80		4.27	64.43	6.87	26.28	16.95	4.00
COST OF SERVICE WITH A&G ALLOCATION		TOTAL RETAIL RATE		NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION		
Souther California Edison		105.98		2.80	71.21	7.36	24.61		
LOS ANGELES 95		94.75		4.27	54.86	6.56	29.06		
LOS ANGELES 95	Adjusted	122.80		4.27	64.93	10.22	43.38		
MUNI AS PERCENT OF IOU WITH ALLOCATION									
Without Cost of Capital Adjustment		89.41%		152.56%	76.46%	51.88%	58.32%		
With Cost of Capital Adjustment		115.88%		152.56%	91.19%	138.96%	176.26%		
CSOT OF SERVICE WITHOUT A&G ALLOCATION		TOTAL RETAIL RATE		NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION	ADMIN & GENERAL	CUSTOMER SERVICE
Souther California Edison		105.98		2.80	66.16	6.32	15.70	11.72	3.27
LOS ANGELES 95		94.75		4.27	54.45	3.82	14.35	13.87	4.00
LOS ANGELES 95	Adjusted	122.80		4.27	64.43	6.87	26.28	16.95	4.00
MUNI AS PERCENT OF IOU WITHOUT ALLOCATION									
Without Cost of Capital Adjustment		89.41%		152.56%	82.30%	60.37%	91.39%	118.30%	122.16%
With Cost of Capital Adjustment		115.88%		152.56%	97.39%	108.65%	167.35%	144.66%	122.16%
Souther California Edison	Customers	3678.251		3678.251	3678.251	3678.251	3678.251	3678.251	3678.251
LOS ANGELES 95	Customers	1343.48		1343.48	1343.48	1343.48	1343.48	1343.48	1343.48
Souther California Edison	Cost/Customer	2,059.52		54.40	1,285.66	122.91	305.17	227.77	63.62
LOS ANGELES 95	Cost/Customer	1,446.71		65.20	831.31	58.30	219.13	211.71	61.06
LOS ANGELES 95	Adj Cost/Customer	1,875.07		65.20	983.76	104.92	401.25	258.87	61.06
Muni/IOU at actual cost of capital							71.81%	92.95%	95.98%
							131.49%	113.65%	95.98%
OPERATION AND MAINTENANCE COSTS									
Souther California Edison	Cost/kWhr	66.83		0.00	50.92	1.13	2.48	9.03	3.27
LOS ANGELES 95	Cost/kWhr	72.96			49.24	1.74	6.22	11.76	4.00

Muni/IOU Ratio		109.17%	96.71%	153.17%	250.98%	130.26%	122.16%
Souther California Edison	Cost/Customer				48,168.43	175,445.24	63,617.69
LOS ANGELES 95	Cost/Customer				94,985.04	179,552.52	61,059.48
					197.19%	102.34%	95.98%

SEATTLE 95

Item	Source	Total	Reconciliation	Taxes	Production	Transmission	Distribution	General	
Revenues	SCHEDULE 2, LINE	329,808							
Operation & Maintenance	SCHEDULE 2, LINE	214,438	214,438		107,784	17,586	33,104		
Depreciation Expense	SCHEDULE 2, LINE	39,607	39,607		14,061	2,571	18,167	4,808	
General Taxes Property Taxes	SCHEDULE 4, LINE	0							
Amortization	SCHEDULE 4, LINE --				--				
Pre-tax Income	Rev-O&M-Dep-Tax	75,763							
Gross Plant Gross Plant Percent	SCHEDULE 3, LINE	1,345,383	1,345,383		477,636 35.50%	87,337 6.49%	617,107 45.87%	163,303 12.14%	
Accumulated Depreciation	SCHEDULE 1, LINE --				0	0	0	0	
Net Nuclear Fuel	SCHEDULE 1, LINE --				--				
Deferred Costs on Gen Plt	SCHEDULE 1, LINE	108,403			108,403				
Total Net Plant		1,453,785			586,039	87,337	617,107	163,303	
Rate of Return on Net Plant	Income/Net Plt	5.21%	13.87%		13.87%	13.87%	13.87%	13.87%	
Pre-tax Return	Net Plt x ROR	75,763			81,311	12,118	85,622	22,658	
Non-Fuel O&M Percent of Total	Total less Fuel	732,763 100.00%			28,320 3.86%	87336.849 11.92%	617106.879 84.22%		
Alloc Admin & Genl	Depr,O&M,Cap	60,670			2,345	7,231	73,853		
Total Cost to Serve		329,808	125,945 455,754	0	205,502	39,506	210,746		
Less: Sales for resale	SCHEDULE 5, LINE	0			0				
Net cost to serve		329,808			205,502				
Retail sales	SCHEDULE 8, LINE	8,789			8,789	8,789	8,789		
Retail cost/mwh		37.53	51.86	0.00	23.38	4.50	23.98		
Alternate Cost to Serve					203,157	32,275	136,893	60,670	22,759
Alternate Cost/mwh		51.86		0.00	23.12	3.67	15.58	6.90	2.59
Less: Other supply cost					(79,465)				
Net generation	SCHEDULE 8, LINE	7,441			7,441				
Production cost	Cost - Other + S/R				126,037				
Production cost/MWH					16.94				
Retail Production Cost/MWH Generated					22.12				

Total Losses	585
Total Purchases	2,213
Total Output	10,239
LOSS PERCENT	5.71%
Retail Sales	8,789
Employees	2
Sales/Res & Other	

PUGET	1995								
Item	Source	Total	Reconcillation	Taxes	Production	Transmission	Distribution	General	
Revenues	Page 114	1,179,330,189							
Operation & Maintenance	Page 320-322	663,776,673	663,779,673		488,997,448	34,230,236	40,503,184		
Depreciation Expense	Page 336	93,858,311	93,858,311		26,541,084	13,738,647	44,512,925	9,065,655	
General Taxes	Page 114	109,532,659		109,532,659					
Property Taxes	Page 262	21,285,295							
Amortization	Page 114	13,724,069			0				
Pre-tax Income	Rev-O&M-Dep-Tax	298,438,477							
Gross Plant	Page 204	3,239,467,579	0		905,047,665	521,809,808	1,571,077,180	241,532,926	
Accumulated Depreciation	Page 219	1,088,518,092			335,342,239	136,937,633	528,720,073	87,518,147	
Net Nuclear Fuel	Page 110	0			0				
Deferred Costs on Gen Plt	Page 232	0			0				
Total Net Plant		2,150,949,487			569,705,426	384,872,175	1,042,357,107	154,014,779	
Rate of Return on Net Plant	Income/Net Plt	13.87%			13.87%	13.87%	13.87%	13.87%	
Pre-tax Return	Net Plt x ROR	277,069,339			79,045,101	53,399,983	144,624,255		
Salaries excl A&G	Page 354	44,671,703			4,889,132	3,667,651	36,114,920		
Percent of Total		100.00%			10.94%	8.21%	80.85%		
Alloc Admin & Genl	Depr,O&M,Cap	92,297,280			10,101,553	7,577,822	112,804,223		
			(13,721,069)						
Total Cost to Serve		1,179,330,189	1,165,609,120	109,532,659	604,685,186	108,946,688	342,444,587	29,518,881	
		0	0.00%						
Less: Sales for resale	Page 301	(60,080,126)	(57,736,127)		(60,080,126)				
Net cost to serve		1,105,528,994		109,532,659	544,605,060	108,946,688	342,444,587		
Retail sales	Page 301	19,144,638		19,144,638	19,144,638	19,144,638	19,144,638	19,144,638	
Retail cost/mwh	0.00	57.75	57.75	5.72	28.45	5.69	17.89		
Net Cost w/o Admin	0	1,105,528,994		109,532,659	534,503,507	101,368,866	229,640,364	92,297,280	38,186,318
Retail Cost/MWH		57.75		5.72	27.92	5.29	12.00	4.82	1.99
		0							
Less: Other supply cost	Page 321				(410,305,062)				
Net generation	Page 401				6,371,415				
Production cost	Cost - Other + S/R				194,380,124		544605060.31		
Production cost/MWH					30.51		574339140		
Retail Production Cost/MWH Generated					27.16		(29,734,080)		
				Total Losses	1,203,480				
				Total Purchases	17,890,343				
				Total Output	25,465,238				
Net Income				LOSS PERCENT	4.73%				
BOY Common									
EOY Common				Retail Revenues	1,119,250,063				
Avg Common				Employees	2,150				

ROE

ACCUMULATED DEPRECIATION	PAGE 219
Nuclear	250,330,453
Steam	0
Hydro	47,019,700
Pumped Storage	0
Other	37,992,086
Total Production	335,342,239

DEPRECIATION EXPENSE	PAGE 336
Nuclear	17,574,788
Steam	0
Hydro	6,545,568
Pumped Storage	0
Other	2,420,728
Total Production	26,541,084

Salse/Rej & Other (60,080,126)

OTHER EXPENSES	
Cust Acct	20,453,226
Cust Survice	17,733,092
Sales	0
Admin & Gen	61,862,487
Total	100,048,805
Total Less A&G	38,186,318

SEATTLE 95

Puget Power		TOTAL RETAIL RATE		NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION	ADMIN & GENERAL	CUSTOMER SERVIC
Retail cost/mwh	0.00	57.75	57.75	5.72	28.45	5.69	17.89		
Net Cost w/o Admin	0	1,105,528,994		109,532,659	534,503,507	101,368,866	229,640,364	92,297,280	38,186,318
Retail Cost/MWH		57.75		5.72	27.92	5.29	12.00	4.82	1.99
SEATTLE 95	Actual without Cost of Capital Adjustment								
Retail cost/mwh		37.53	37.53	0.00	17.54	3.44	16.54		
Alternate Cost to Serve					152,387	24,709	83,431	46,523	22,759
Alternate Cost/mwh		37.53		0.00	17.34	2.81	9.49	5.29	2.59
SEATTLE 95	with Cost of Capital Adjustment								
Retail cost/mwh		37.53	51.86	0.00	23.38	4.50	23.98		
Alternate Cost to Serve					203,157	32,275	136,893	60,670	22,759
Alternate Cost/mwh		51.86		0.00	23.12	3.67	15.58	6.90	2.59

COST OF SERVICE WITH A&G ALLOCATION		TOTAL RETAIL RATE	NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION
Puget Power		57.75	5.72	28.45	5.69	17.89
SEATTLE 95		37.53	0.00	17.54	3.44	16.54
SEATTLE 95	Adjusted	51.86	0.00	23.38	4.50	23.98
MUNI AS PERCENT OF IOU WITH ALLOCATION						
Without Cost of Capital Adjustment		64.98%	0.00%	60.95%	49.40%	53.07%
With Cost of Capital Adjustment		89.80%	0.00%	82.20%	78.99%	134.06%

COST OF SERVICE WITHOUT A&G ALLOCATION		TOTAL RETAIL RATE	NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION	ADMIN & GENERAL	CUSTOMER SERVIC
Puget Power		57.75	5.72	27.92	5.29	12.00	4.82	1.99
SEATTLE 95		37.53	0.00	17.34	2.81	9.49	5.29	2.59
SEATTLE 95	Adjusted	51.86	0.00	23.12	3.67	15.58	6.90	2.59
MUNI AS PERCENT OF IOU WITHOUT ALLOCATION								
Without Cost of Capital Adjustment		64.98%	0.00%	62.10%	53.10%	79.14%	109.80%	129.82%
With Cost of Capital Adjustment		89.80%	0.00%	82.79%	69.36%	129.85%	143.19%	129.82%
Puget Power	Customers	739,173	739,173	739,173	739,173	739,173	739,173	739,173
SEATTLE 95	Customers	333,625	333,625	333,625	333,625	333,625	333,625	333,625
Puget Power	Cost/Customer	1,495.63	148.18	723.11	137.14	310.67	124.87	51.66
SEATTLE 95	Cost/Customer	988.56	0.00	456.76	74.06	250.08	139.45	68.22
SEATTLE 95	Adj Cost/Customer	1,366.07	0.00	608.94	96.74	410.32	181.85	68.22
Muni/IOU at actual cost of capital						80.49%	111.68%	132.05%
						132.08%	145.64%	132.05%
OPERATION AND MAINTENANCE COSTS								
Puget Power	Cost/kWhr	34.67	0.00	25.54	1.79	2.12	3.23	1.99
SEATTLE 95	Cost/kWhr	24.40		12.26	2.00	3.77	3.78	2.59

Muni/IOU Ratio		70.37%	48.01%	111.91%	178.04%	116.92%	129.82%
Puget Power	Cost/Customer				54,795.27	83,691.49	51,660.87
SEATTLE 95	Cost/Customer				99,224.73	99,527.19	68,216.11
					181.08%	118.92%	132.05%

ALAMEDA 94

Pacific Gas and Electric		TOTAL RETAIL RATE		NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION	ADMIN & GENERAL	CUSTOMER SERVIC
Retail cost/mwh		104.66		3.06	65.58	5.69	30.34		
Net Cost w/o Admin	0	7,569,506,874		221,622,851	4,425,216,546	351,183,483	1,495,620,461	768,876,460	306,987,073
Retail Cost/MWH		104.66		3.06	61.19	4.86	20.68	10.63	4.24
ALAMEDA 94	Actual without Cost of Capital Adjustment								
Retail cost/mwh		92.29	92.29	8.16	62.19	1.54	20.39		
Alternate Cost to Serve					29,790	289	4,070	4,947	1,198
Alternate Cost/mwh		92.29		8.16	62.19	0.60	8.50	10.33	2.50
ALAMEDA 94	with Cost of Capital Adjustment								
Retail cost/mwh		92.29	100.56	8.16	62.19	2.29	27.91		
Alternate Cost to Serve					29,790	586	7,053	5,630	1,198
Alternate Cost/mwh		100.56		8.16	62.19	1.22	14.72	11.75	2.50

COST OF SERVICE WITH A&G ALLOCATION		TOTAL RETAIL RATE	NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION
Pacific Gas and Electric		104.66	3.06	65.58	5.69	30.34
ALAMEDA 94		92.29	8.16	62.19	1.54	20.39
ALAMEDA 94	Adjusted	100.56	8.16	62.19	2.29	27.91
MUNI AS PERCENT OF IOU WITH ALLOCATION						
Without Cost of Capital Adjustment		88.17%	266.45%	94.84%	10.60%	28.01%
With Cost of Capital Adjustment		96.08%	266.45%	94.84%	40.24%	92.01%

COST OF SERVICE WITHOUT A&G ALLOCATION		TOTAL RETAIL RATE	NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION	ADMIN & GENERAL	CUSTOMER SERVIC
Pacific Gas and Electric		104.66	3.06	61.19	4.86	20.68	10.63	4.24
ALAMEDA 94		92.29	8.16	62.19	0.60	8.50	10.33	2.50
ALAMEDA 94	Adjusted	100.56	8.16	62.19	1.22	14.72	11.75	2.50
MUNI AS PERCENT OF IOU WITHOUT ALLOCATION								
Without Cost of Capital Adjustment		88.17%	266.45%	101.64%	12.42%	41.09%	97.14%	58.92%
With Cost of Capital Adjustment		96.08%	266.45%	101.64%	25.20%	71.20%	110.56%	58.92%
Pacific Gas and Electric	Customers	4387.019	4387.019	4387.019	4387.019	4387.019	4387.019	4387.019
ALAMEDA 94	Customers	31.445	31.445	31.445	31.445	31.445	31.445	31.445
Pacific Gas and Electric	Cost/Customer	1,725.43	50.52	1,008.71	80.05	340.92	175.26	69.98
ALAMEDA 94	Cost/Customer	1,405.79	124.38	947.37	9.19	129.45	157.31	38.10
ALAMEDA 94	Adj Cost/Customer	1,531.82	124.38	947.37	18.64	224.29	179.04	38.10
Muni/IOU at actual cost of capital						37.97%	89.76%	54.44%
						65.79%	102.16%	54.44%
OPERATION AND MAINTENANCE COSTS								
Pacific Gas and Electric	Cost/kWhr	52.86	0.00	35.77	1.03	3.90	7.92	4.24

ALAMEDA 94	Cost/kWhr	76.47	62.19	0.03	2.7¢	9.01	2.50
Muni/IOU Ratio		144.66%	173.86%	2.85%	70.32%	113.71%	58.92%
Pacific Gas and Electric	Cost/Customer				64,264.66	130,599.24	69,976.24
ALAMEDA 94	Cost/Customer				41,755.45	137,223.72	38,098.27
					64.97%	105.07%	54.44%

ANAHEIM 94

Pacific Gas and Electric		TOTAL RETAIL RATE		NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION	ADMIN & GENERAL	CUSTOMER SERVIC
Retail cost/mwh		104.66		3.06	65.58	5.69	30.34		
Net Cost w/o Admin	0	7,569,506,874		221,622,851	4,425,216,546	351,183,403	1,495,620,461	768,876,460	306,987,073
Retail Cost/MWH		104.66		3.06	61.19	4.86	20.68	10.63	4.24
ANAHEIM 94	Actual without Cost of Capital Adjustment								
Retail cost/mwh		98.36	98.36	4.28	73.75	7.11	13.22		
Alternate Cost to Serve					162,612	15,343	19,388	4,739	5,834
Alternate Cost/mwh		98.36		4.28	73.58	6.94	8.77	2.14	2.64
ANAHEIM 94	with Cost of Capital Adjustment								
Retail cost/mwh		98.36	121.40	4.28	88.44	7.84	20.84		
Alternate Cost to Serve					194,742	16,602	32,604	9,050	5,834
Alternate Cost/mwh		121.40		4.28	88.12	7.51	14.75	4.09	2.64
COST OF SERVICE WITH A&G ALLOCATION		TOTAL RETAIL RATE		NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION		
Pacific Gas and Electric		104.66		3.06	65.58	5.69	30.34		
ANAHEIM 94		98.36		4.28	73.75	7.11	13.22		
ANAHEIM 94	Adjusted	121.40		4.28	88.44	7.84	20.84		
MUNI AS PERCENT OF IOU WITH ALLOCATION									
Without Cost of Capital Adjustment		93.97%		139.61%	112.21%	122.05%	28.92%		
With Cost of Capital Adjustment		115.99%		139.61%	134.87%	137.84%	68.69%		
COST OF SERVICE WITHOUT A&G ALLOCATION		TOTAL RETAIL RATE		NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION	ADMIN & GENERAL	CUSTOMER SERVIC
Pacific Gas and Electric		104.66		3.06	61.19	4.86	20.68	10.63	4.24
ANAHEIM 94		98.36		4.28	73.58	6.94	8.77	2.14	2.64
ANAHEIM 94	Adjusted	121.40		4.28	88.12	7.51	14.75	4.09	2.64
MUNI AS PERCENT OF IOU WITHOUT ALLOCATION									
Without Cost of Capital Adjustment		93.97%		139.61%	120.25%	142.98%	42.42%	20.17%	62.19%
With Cost of Capital Adjustment		115.99%		139.61%	144.01%	154.71%	71.34%	38.52%	62.19%
Pacific Gas and Electric	Customers	4387.019		4387.019	4387.019	4387.019	4387.019	4387.019	4387.019
ANAHEIM 94	Customers	103.937		103.937	103.937	103.937	103.937	103.937	103.937
Pacific Gas and Electric	Cost/Customer	1,725.43		50.52	1,008.71	80.05	340.92	175.26	69.98
ANAHEIM 94	Cost/Customer	2,091.37		90.97	1,564.52	147.62	186.54	45.59	56.13
ANAHEIM 94	Adj Cost/Customer	2,581.25		90.97	1,873.66	159.73	313.69	87.07	56.13
Muni/IOU at actual cost of capital							54.72%	26.01%	80.21%
							92.01%	49.68%	80.21%
OPERATION AND MAINTENANCE COSTS									
Pacific Gas and Electric	Cost/kWhr	52.86		0.00	35.77	1.03	3.90	7.92	4.24

ANAHEIM 94	Cost/kWhr	81.50	68.2¢	6.4¢	3.6¢	0.4¢	2.6¢
Muni/IOU Ratio		154.17%	190.75%	629.01%	94.47%	6.11%	62.19%
Pacific Gas and Electric	Cost/Customer				64,264.66	130,599.24	69,976.24
ANAHEIM 94	Cost/Customer				78,307.05	10,285.08	56,130.16
					121.85%	7.88%	80.21%

COST OF SERVICE WITH A&G ALLOCATION		TOTAL RETAIL RATE	NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION		
Pacific Gas and Electric		104.66	3.06	65.58	5.69	30.34		
BURBANK 94		96.35	6.07	70.56	2.14	17.59		
BURBANK 94	Adjusted	103.69	6.07	72.81	3.08	21.73		
MUNI AS PERCENT OF IOU WITH ALLOCATION								
Without Cost of Capital Adjustment		92.06%	197.99%	105.88%	15.85%	36.46%		
With Cost of Capital Adjustment		99.07%	197.99%	111.03%	54.11%	71.64%		
COST OF SERVICE WITHOUT A&G ALLOCATION		TOTAL RETAIL RATE	NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION	ADMIN & GENERAL	CUSTOMER SERVIC
Pacific Gas and Electric		104.66	3.06	61.19	4.86	20.68	10.63	4.24
BURBANK 94		96.35	6.07	69.43	0.90	11.06	7.79	1.11
BURBANK 94	Adjusted	103.69	6.07	71.61	1.77	14.86	8.28	1.11
MUNI AS PERCENT OF IOU WITHOUT ALLOCATION								
Without Cost of Capital Adjustment		92.06%	197.99%	113.47%	18.57%	53.48%	73.28%	26.08%
With Cost of Capital Adjustment		99.07%	197.99%	117.03%	36.36%	71.85%	77.90%	26.08%
Pacific Gas and Electric	Customers	4387.019	4387.019	4387.019	4387.019	4387.019	4387.019	4387.019
BURBANK 94	Customers	50.972	50.972	50.972	50.972	50.972	50.972	50.972
Pacific Gas and Electric	Cost/Customer	1,725.43	50.52	1,008.71	80.05	340.92	175.26	69.98
BURBANK 94	Cost/Customer	1,801.50	113.43	1,298.07	16.86	206.77	145.66	20.70
BURBANK 94	Adj Cost/Customer	1,938.57	113.43	1,338.78	33.01	277.79	154.85	20.70
Muni/IOU at actual cost of capital						60.65%	83.11%	29.58%
						81.48%	88.35%	29.58%

COST OF SERVICE WITH A&G ALLOCATION		TOTAL RETAIL RATE	NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION		
Pacific Gas and Electric		104.66	3.06	65.58	5.69	30.34		
GLENDALE 94		97.40	10.21	59.84	6.58	20.77		
GLENDALE 94	Adjusted	117.95	10.21	64.38	11.44	31.92		
MUNI AS PERCENT OF IOU WITH ALLOCATION								
Without Cost of Capital Adjustment		93.06%	333.20%	89.39%	58.59%	33.32%		
With Cost of Capital Adjustment		112.69%	333.20%	98.17%	201.05%	105.24%		
COST OF SERVICE WITHOUT A&G ALLOCATION		TOTAL RETAIL RATE	NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION	ADMIN & GENERAL	CUSTOMER SERVIC
Pacific Gas and Electric		104.66	3.06	61.19	4.86	20.68	10.63	4.24
GLENDALE 94		97.40	10.21	58.62	3.33	10.11	11.93	3.20
GLENDALE 94	Adjusted	117.95	10.21	62.83	7.33	19.30	15.08	3.20
MUNI AS PERCENT OF IOU WITHOUT ALLOCATION								
Without Cost of Capital Adjustment		93.06%	333.20%	95.80%	68.64%	48.88%	112.21%	75.42%
With Cost of Capital Adjustment		112.69%	333.20%	102.68%	151.03%	93.32%	147.81%	75.42%
Pacific Gas and Electric	Customers	4387.019	4387.019	4387.019	4387.019	4387.019	4387.019	4387.019
GLENDALE 94	Customers	82.496	82.496	82.496	82.496	82.496	82.496	82.496
Pacific Gas and Electric	Cost/Customer	1,725.43	50.52	1,008.71	80.05	340.92	175.26	69.98
GLENDALE 94	Cost/Customer	1,154.69	121.05	694.90	39.51	119.85	141.43	37.95
GLENDALE 94	Adj Cost/Customer	1,398.28	121.05	744.81	86.94	228.80	178.73	37.95
Muni/IOU at actual cost of capital						35.15%	80.70%	54.24%
OPERATION AND MAINTENANCE COSTS								
Pacific Gas and Electric	Cost/kWhr	52.86	0.00	35.77	1.03	3.90	7.92	4.24
GLENDALE 94	Cost/kWhr	76.53		56.78	1.17	5.15	10.23	3.20
Muni/IOU Ratio		144.77%		158.72%	114.23%	132.04%	129.15%	75.42%
Pacific Gas and Electric	Cost/Customer					64,264.66	130,599.24	69,976.24
GLENDALE 94	Cost/Customer					61,021.14	121,290.73	37,953.36
						94.95%	92.87%	54.24%

COST OF SERVICE WITH A&G ALLOCATION		TOTAL RETAIL RATE	NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION		
Pacific Gas and Electric		104.66	3.06	65.58	5.69	30.34		
PALO ALTO 94		38.04	9.09	29.15	0.00	10.31		
PALO ALTO 94	Adjusted	61.97	9.09	29.15	0.00	23.73		
MUNI AS PERCENT OF IOU WITH ALLOCATION								
Without Cost of Capital Adjustment		46.38%	296.53%	44.45%	0.00%	24.62%		
With Cost of Capital Adjustment		59.21%	296.53%	44.45%	0.00%	78.24%		
COST OF SERVICE WITHOUT A&G ALLOCATION		TOTAL RETAIL RATE	NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION	ADMIN & GENERAL	CUSTOMER SERVICE
Pacific Gas and Electric		104.66	3.06	61.19	4.86	20.68	10.63	4.24
PALO ALTO 94		48.54	9.09	29.15	0.00	7.47	1.48	1.36
PALO ALTO 94	Adjusted	61.97	9.09	29.15	0.00	20.90	1.48	1.36
MUNI AS PERCENT OF IOU WITHOUT ALLOCATION								
Without Cost of Capital Adjustment		36.34%	296.53%	47.64%	0.00%	36.12%	13.95%	31.93%
With Cost of Capital Adjustment		59.21%	296.53%	47.64%	0.00%	101.04%	13.95%	31.93%
Pacific Gas and Electric	Customers	4387.019	4387.019	4387.019	4387.019	4387.019	4387.019	4387.019
PALO ALTO 94	Customers	27.411	27.411	27.411	27.411	27.411	27.411	27.411
Pacific Gas and Electric	Cost/Customer	1,725.43	50.52	1,008.71	80.05	340.92	175.26	69.98
PALO ALTO 94	Cost/Customer	1,854.22	347.09	1,113.42	0.00	285.29	56.66	51.77
PALO ALTO 94	Adj Cost/Customer	2,367.09	347.09	1,113.42	0.00	798.15	56.66	51.77
Muni/IOU at actual cost of capital						83.68%	32.33%	73.98%
						234.12%	32.33%	73.98%

COST OF SERVICE WITH A&G ALLOCATION		TOTAL RETAIL RATE	NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION		
Pacific Gas and Electric		104.66	3.06	65.58	5.69	30.34		
REDDING 94		77.18	0.00	44.70	0.00	32.48		
REDDING 94	Adjusted	102.33	0.00	48.76	0.00	53.57		
MUNI AS PERCENT OF IOU WITH ALLOCATION								
Without Cost of Capital Adjustment		73.74%	0.00%	67.84%	0.00%	46.64%		
With Cost of Capital Adjustment		97.77%	0.00%	74.36%	0.00%	176.59%		
COST OF SERVICE WITHOUT A&G ALLOCATION		TOTAL RETAIL RATE	NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION	ADMIN & GENERAL	CUSTOMER SERVIC
Pacific Gas and Electric		104.66	3.06	61.19	4.86	20.68	10.63	4.24
REDDING 94		77.18	0.00	44.49	0.00	14.15	16.91	1.64
REDDING 94	Adjusted	102.33	0.00	48.54	0.00	35.24	16.91	1.64
MUNI AS PERCENT OF IOU WITHOUT ALLOCATION								
Without Cost of Capital Adjustment		73.74%	0.00%	72.71%	0.00%	68.42%	159.04%	38.60%
With Cost of Capital Adjustment		97.77%	0.00%	79.33%	0.00%	170.41%	159.04%	38.60%
Pacific Gas and Electric	Customers	4387.019	4387.019	4387.019	4387.019	4387.019	4387.019	4387.019
REDDING 94	Customers	34.431	34.431	34.431	34.431	34.431	34.431	34.431
Pacific Gas and Electric	Cost/Customer	1,725.43	50.52	1,008.71	80.05	340.92	175.26	69.98
REDDING 94	Cost/Customer	1,439.14	0.00	829.50	0.00	263.82	315.27	30.55
REDDING 94	Adj Cost/Customer	1,908.04	0.00	905.13	0.00	657.09	315.27	30.55
Muni/IOU at actual cost of capital						77.38%	179.88%	43.66%
						192.74%	179.88%	43.66%

RIVERSIDE 94

Pacific Gas and Electric		TOTAL RETAIL RATE		NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION	ADMIN & GENERAL	CUSTOMER SERVIC
Retail cost/mwh		104.66		3.06	65.58	5.69	30.34		
Net Cost w/o Admin	0	7,569,506,874		221,622,851	4,425,216,546	351,183,483	1,495,620,461	768,876,460	306,987,073
Retail Cost/MWH		104.66		3.06	61.19	4.86	20.68	10.63	4.24
RIVERSIDE 94	Actual without Cost of Capital Adjustment								
Retail cost/mwh		103.98	103.98	10.50	64.03	10.33	19.12		
Alternate Cost to Serve					97,258	14,801	15,515	11,484	3,969
Alternate Cost/mwh		103.98		10.50	63.57	9.67	10.14	7.51	2.59
RIVERSIDE 94	with Cost of Capital Adjustment								
Retail cost/mwh		103.98	119.04	10.50	70.84	11.09	26.61		
Alternate Cost to Serve					107,627	15,914	26,388	12,167	3,969
Alternate Cost/mwh		119.04		10.50	70.34	10.40	17.25	7.95	2.59

COST OF SERVICE WITH A&G ALLOCATION		TOTAL RETAIL RATE	NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION
Pacific Gas and Electric		104.66	3.06	65.58	5.69	30.34
RIVERSIDE 94		103.98	10.50	64.03	10.33	19.12
RIVERSIDE 94	Adjusted	119.04	10.50	70.84	11.09	26.61
MUNI AS PERCENT OF IOU WITH ALLOCATION						
Without Cost of Capital Adjustment		99.35%	342.75%	96.94%	170.06%	33.43%
With Cost of Capital Adjustment		113.74%	342.75%	108.03%	195.03%	87.71%

COST OF SERVICE WITHOUT A&G ALLOCATION		TOTAL RETAIL RATE	NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION	ADMIN & GENERAL	CUSTOMER SERVIC
Pacific Gas and Electric		104.66	3.06	61.19	4.86	20.68	10.63	4.24
RIVERSIDE 94		103.98	10.50	63.57	9.67	10.14	7.51	2.59
RIVERSIDE 94	Adjusted	119.04	10.50	70.34	10.40	17.25	7.95	2.59
MUNI AS PERCENT OF IOU WITHOUT ALLOCATION								
Without Cost of Capital Adjustment		99.35%	342.75%	103.89%	199.22%	49.03%	70.60%	61.11%
With Cost of Capital Adjustment		113.74%	342.75%	114.96%	214.20%	83.40%	74.80%	61.11%
Pacific Gas and Electric	Customers	4387.019	4387.019	4387.019	4387.019	4387.019	4387.019	4387.019
RIVERSIDE 94	Customers	88.414	88.414	88.414	88.414	88.414	88.414	88.414
Pacific Gas and Electric	Cost/Customer	1,725.43	50.52	1,008.71	80.05	340.92	175.26	69.98
RIVERSIDE 94	Cost/Customer	1,799.44	181.76	1,100.03	167.40	175.48	129.88	44.89
RIVERSIDE 94	Adj Cost/Customer	2,060.01	181.76	1,217.30	179.99	298.46	137.61	44.89
Muni/IOU at actual cost of capital						51.47%	74.11%	64.15%
						87.54%	78.52%	64.15%
OPERATION AND MAINTENANCE COSTS								
Pacific Gas and Electric	Cost/kWhr	52.86	0.00	35.77	1.03	3.90	7.92	4.24
RIVERSIDE 94	Cost/kWhr	82.01		59.34	9.04	3.93	7.12	2.59

Muni/IOU Ratio		155.13%	165.88%	880.25%	100.72%	89.81%	61.11%
Pacific Gas and Electric	Cost/Customer				64,264.66	130,599.24	69,976.24
RIVERSIDE 94	Cost/Customer				67,941.73 105.72%	123,125.30 94.28%	44,891.08 64.15%

COST OF SERVICE WITH A&G ALLOCATION		TOTAL RETAIL RATE	NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION
Pacific Gas and Electric		104.66	3.06	65.58	5.69	30.34
SANTA CLARA 94		78.08	0.00	76.52	0.08	1.49
SANTA CLARA 94	Adjusted	88.36	0.00	86.79	0.08	1.49
MUNI AS PERCENT OF IOU WITH ALLOCATION						
Without Cost of Capital Adjustment		74.61%	0.00%	95.91%	1.40%	4.81%
With Cost of Capital Adjustment		84.42%	0.00%	132.35%	1.40%	4.90%

COST OF SERVICE WITHOUT A&G ALLOCATION		TOTAL RETAIL RATE	NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION	ADMIN & GENERAL	CUSTOMER SERVIC
Pacific Gas and Electric		104.66	3.06	61.19	4.86	20.68	10.63	4.24
SANTA CLARA 94		78.09	0.00	62.89	0.08	1.46	13.63	0.03
SANTA CLARA 94	Adjusted	88.36	0.00	69.10	0.08	1.46	17.69	0.03
MUNI AS PERCENT OF IOU WITHOUT ALLOCATION								
Without Cost of Capital Adjustment		74.60%	0.00%	102.79%	1.65%	7.05%	128.19%	0.67%
With Cost of Capital Adjustment		84.42%	0.00%	112.93%	1.65%	7.05%	166.39%	0.67%
Pacific Gas and Electric	Customers	4387.019	4387.019	4387.019	4387.019	4387.019	4387.019	4387.019
SANTA CLARA 94	Customers	45.973	45.973	45.973	45.973	45.973	45.973	45.973
Pacific Gas and Electric	Cost/Customer	1,725.43	50.52	1,008.71	80.05	340.92	175.26	69.98
SANTA CLARA 94	Cost/Customer	3,699.56	0.00	2,979.69	3.78	69.11	645.63	1.35
SANTA CLARA 94	Adj Cost/Customer	4,186.00	0.00	3,273.71	3.78	69.11	838.05	1.35
Muni/IOU at actual cost of capital						20.27%	368.38%	1.93%
						20.27%	478.17%	1.93%

COST OF SERVICE WITH A&G ALLOCATION		TOTAL RETAIL RATE	NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION		
Pacific Gas and Electric		104.66	3.06	65.58	5.69	30.3¢		
VERNON 94		54.15	1.57	35.53	9.51	7.54		
VERNON 94	Adjusted	57.50	1.57	35.73	11.74	8.46		
MUNI AS PERCENT OF IOU WITH ALLOCATION								
Without Cost of Capital Adjustment		51.73%	51.29%	53.94%	124.86%	20.32%		
With Cost of Capital Adjustment		54.94%	51.29%	54.49%	206.32%	27.89%		
COST OF SERVICE WITHOUT A&G ALLOCATION		TOTAL RETAIL RATE	NON INC TAX	PRODUCTION	TRANSMISSION	DISTRIBUTION	ADMIN & GENERAL	CUSTOMER SERVIC
Pacific Gas and Electric		104.66	3.06	61.19	4.86	20.68	10.63	4.24
VERNON 94		54.15	1.57	35.37	7.10	6.17	3.57	0.37
VERNON 94	Adjusted	57.50	1.57	35.57	9.26	7.06	3.67	0.37
MUNI AS PERCENT OF IOU WITHOUT ALLOCATION								
Without Cost of Capital Adjustment		51.73%	51.29%	57.81%	146.27%	29.81%	33.58%	8.63%
With Cost of Capital Adjustment		54.94%	51.29%	58.14%	190.69%	34.15%	34.48%	8.63%
Pacific Gas and Electric	Customers	4387.019	4387.019	4387.019	4387.019	4387.019	4387.019	4387.019
VERNON 94	Customers	1.977	1.977	1.977	1.977	1.977	1.977	1.977
Pacific Gas and Electric	Cost/Customer	1,725.43	50.52	1,008.71	80.05	340.92	175.26	69.98
VERNON 94	Cost/Customer	28,265.05	820.44	18,464.08	3,707.52	3,218.49	1,863.31	191.20
VERNON 94	Adj Cost/Customer	30,014.93	820.44	18,569.49	4,833.54	3,687.01	1,913.25	191.20
Muni/IOU at actual cost of capital						944.06%	1063.16%	273.23%
						1081.49%	1091.65%	273.23%

Workpapers

Chapter 2

Valuation

SUMMARY OF TRANSACTIONS

	TYPE	DATE	DESCRIPTION	BUYER(S)	SELLER(S)	BOOK VALUE	VALUATION METHOD	$ AMOUNT	SOURCE	DEC. NO.	APP. NO.
1	VT	2/1/95	Electric distribution system	City of Gridley	PG&E			$ 20,190 00	FERC FORM 1		
2	VT	1995	Electric distribution facilities	Hayfork Valley PUD	PG&E			$ 1,214,935 00	FERC FORM 1		
3	VT	1995	Sale of street light systems	City of Vacaville	PG&E			$ (436,987 00)	FERC FORM 1		
4	VT	12/31/95	Street light system	City of Carlsbad	SDG&E		(Note footnote)	$ 4,880 00	FERC FORM 1		
5	VT	12/31/95	Street light system	City of Oceanside	SDG&E		(Note footnote)		FERC FORM 1		
6	CC	6/16/94	Electric distribution system	Hayfork Valley PUD/Trinity County	PG&E			$ 449,072 00	FERC FORM 1		
7	VT	1994	Street light systems	City of Fairfield	PG&E			$ 361,286 00	FERC FORM 1		
8	VT	1994	Street light systems	City of Fresno	PG&E			$ (5,336,971.00)	FERC FORM 1		
9	VT	1994	Street light systems	City of Rohnert Park	PG&E			$ 40.00	FERC FORM 1		
10	VT	1994	Street light systems	City of Stockton	PG&E			$ (1 00)	FERC FORM 1		
11	VT	1994	Electric distribution facilities	County of Trinity	PG&E			$ 10,670 00	FERC FORM 1		
12	CC	1994	Electric distribution facilities	Hayfork Valley PUD	PG&E			$ (449,072 00)	FERC FORM 1		
13	VT	1993	Energy growth partnership (operating facilities)	Energy Growth Partnership	PG&E			$ 16,380 00	FERC FORM 1		
14	VT	1993	Real Property (Supplement)	Santa Clara County	PG&E			$ 214,000 00	FERC FORM 1		
15	VT	7/22/93	Substation facilities	Schuller International	PG&E			$ 1,053,000 00	FERC FORM 1		
16	VT	1993	Miscellaneous electric facilities	SFPP, LP	PG&E			$ 142,880 00	FERC FORM 1		
17	VT	2/11/93	Electric distribution equipment	City of S SF San Mateo Co	PG&E			$ 5,340 00	FERC FORM 1		
18	VT	2/15/93	Pole Line, unincorporated area of Mendocino County	PG&E	Raymond Coolidge			$ 700 00	FERC FORM 1		
19	VT	3/4/93	Electric distribution equipment-Unincorporated area-Yolo County	The Carlon Co	PG&E			$ 44,000 00	FERC FORM 1		
20	VT	4/26/93	Electric distribution equipment-Richmond, Contra Costa Co	SFPP, L P.	PG&E			$ 57,100 00	FERC FORM 1		
21	VT	4/30/93	Pole Line, unincorporated area of Shasta County	PG&E	Fall River Dev Co			$ 24,800 00	FERC FORM 1		
22	VT	5/4/93	Electric distribution equipment-Brentwood, Contra Costa County	SFPP, L.P.	PG&E			$ 3,700 00	FERC FORM 1		
23	VT	5/7/93	Electric distribution system-Annexation #68	City of Lompoc Lompoc Airport	PG&E	$ 3,250 00	RCLD+GCV+ SEV. COSTS	$ 18,246 00	FERC FORM 1	93-05-002	92-10-032

SUMMARY OF TRANSACTIONS

	TYPE	DATE	DESCRIPTION	BUYER(S)	SELLER(S)	BOOK VALUE	VALUATION METHOD	$ AMOUNT	SOURCE	DEC. NO.	APP. NO.
24	VT	5/19/93	Electric distribution system-Annexation #90-8	City of Redding-Hollow Lane	PG&E	$ 39,000.00	RCLD+15%GCV+ (Note footnotes)	$ 74,750.00	FERC FORM 1	93-05-042	93-02-046
25	VT	5/19/93	Electric distribution system-Annexation #88-12	City of Redding-Collyer Drive	PG&E	$ 19,000.00	RCLD+15%GCV+ SEV. COSTS	$ 40,480.00	FERC FORM 1 (Note footnote)	93-05-042	92-12-009
26	VT	6/2/93	Electric distribution system	Trinity County PUD	PG&E			$ 8,384,000.00	FERC FORM 1		
27	VT	6/3/93	Steam heat system-City& Co. of SF.	SFT, L P	PG&E			$ 8,800,000.00	FERC FORM 1		
28	VT	6/4/93	Electric distribution system-Woodbridge, San Joaquin Co.	Robt Mondavi Winery	PG&E			$ 33,700.00	FERC FORM 1		
29	VT	6/24/93	Substation, Cisco Grove, Placer Co.	SFPP, L.P.	PG&E			$ 12,800.00	FERC FORM 1		
30	VT	6/24/93	Substation, Rocklin Placer Co.	SFPP, L.P. of Santa Cruz Inc	PG&E			$ 36,280.00	FERC FORM 1		
31	VT	6/24/93	Substation, Unincorporated area-Placer County	SFPP, L.P.	PG&E			$ 31,200.00	FERC FORM 1		
32	VT	6/28/93	Electric distribution system-Annexation #90-15	City of Redding-Tierra Oaks	PG&E		RCLD+15%GCV+ SEV. COSTS	$ 65,127.00	FERC FORM 1 & Redding Elec.	93-06-008	
33	VT	6/30/93	Electric distribution system-Lompoc, Santa Barbara County	Grefco Inc.	PG&E			$ 31,500.00	FERC FORM 1		
34	VT	6/30/93	Electric distribution system-Sonoma, Sonoma County	Sonoma Valley Hospital District	PG&E			$ 32,450.00	FERC FORM 1		
35	VT	7/27/93	Electric distribution system-Annexation #91-6	City of Redding-Hawley Rd. North	PG&E		RCLD+15%GCV+ SEV. COSTS	$ 701,745.00	FERC FORM 1 & Redding Elec.		
36	VT	7/27/93	Electric distribution system-Annexation #91-7	City of Redding-Westside Road	PG&E		RCLD+15%GCV+ SEV. COSTS	$ 24,233.00	FERC FORM 1 & Redding Elec.		
37	VT	8/4/93	transfer & purchase of public utility assets & customer accts. to provide radiotelephon e operations-Kern Co.	Clear-Page, Inc	Communications Enterprises-Public Utility	$ 36,161.00	BK. Value+10% Int in equal payments over 60 months+ add facilities of $60,000	$ 36,161.00 + 10% interest + $ 60,000.00	PUC Decision	93-08-008	92-10-015
38	VT	9/15/93	Electric distribution system-Lakeport, Lake County	Sutter Lake Hospital	PG&E			$ 10,800.00	FERC FORM 1		
39	VT	10/19/93	Street light system-Sonoma Co.	City of Rohnert Park	PG&E			$ 750,903.00	FERC FORM 1		
40	VT	11/5/93	Electric distribution system-Oakland, Alameda County	Childrens Hospital	PG&E			$ 21,700.00	FERC FORM 1		
41	VT	11/10/93	Electric distribution system-San Joaquin Co.	University of the Pacific	PG&E			$ 20,359.00	FERC FORM 1		
42	VT	11/18/93	Street light system-Solano County	City of Vallejo	PG&E			$ 1,774,874.00	FERC FORM 1		
43	VT	11/19/93	Underground Line, Pacifica San Mateo County	PG&E	William D. Carter			$ 1,850.00	FERC FORM 1		

SUMMARY OF TRANSACTIONS

	TYPE	DATE	DESCRIPTION	BUYER(S)	SELLER(S)	BOOK VALUE	VALUATION METHOD	$ AMOUNT	SOURCE	DEC. NO.	APP. NO.
44	VT	12/14/93	Electric distribution system-Mountain View, Santa Clsra Co	Unisil Corporation	PG&E			$ 575.00	FERC FORM 1		
45	VT	12/14/93	Substation-Sunnyvale, Santa Clsra County	Advanced Micro Devices	PG&E			$ 526,400.00	FERC FORM 1		
46	VT	12/20/93	Electric distribution system-Oakland, Alsmeda County	Mother's Cake & Cookie Company	PG&E			$ 23,900.00	FERC FORM 1		
47	VT	12/22/93	Electric distribution system-San Jose, Santa Clsra Co	United Technologies	PG&E			$ 4,000.00	FERC FORM 1		
48	VT	12/31/93	Street light systems	City of Benecia	PG&E			$ 53,595.00	FERC FORM 1		
49	VT	12/31/93	Street light systems	City of Benecia	PG&E			$ 134,848.00	FERC FORM 1		
50	VT	12/31/93	Street light systems	City of Dixon	PG&E			$ 96,799.00	FERC FORM 1		
51	VT	12/31/93	Street light systems	City of Solano	PG&E			$ 27,501.00	FERC FORM 1		
52	VT	12/31/93	Street light systems	City of Suisun	PG&E			$ 204,431.00	FERC FORM 1		
53	VT	12/31/93	Street light systems	City of Fairfield	PG&E			$ 219,698.00	FERC FORM 1		
54	VT	12/31/93	Street light systems	City of Vacaville	PG&E			$ 436,987.00	FERC FORM 1		
55	VT	12/31/93	Street light systems	City of Fresno	PG&E			$ 8,185,661.00	FERC FORM 1		
56	VT	12/31/93	Street light systems	City of Rohnert Park	PG&E			$ (41.00)	FERC FORM 1		
57	VT	12/31/93	Street light systems	City of Sonoma	PG&E			$ (82,000.00)	FERC FORM 1		
58	VT	2/20/92 5/20/92	Electric distribution system Annexation #86-66/Norton Additon Annexation #168-79/Old Redwood Hy Annexation #103-87/Oak Mound Is.	City of Healdsburg	PG&E	$ 3,650.00	$ 13,504.00 +SEV COSTS+ 15% GCV	$ 13,504.00 (Note footnote)	FERC FORM 1 FERC FORM 1 FERC FORM 1 FERC FORM 1	92-02-050 91-10-073 91-10-073 91-10-073	
59	VT	3/24/92	Electric distribution equipment Ripon, San Joaquin Co	Nulaid Foods	PG&E			$ 29,600.00	FERC FORM 1		
60	VT	1/21/92	Substation-Antioch, Contra Costa Co.	E I DuPont de Nemours	PG&E			$ 478,000.00	FERC FORM 1		
61	VT	3/2/92	Electric distribution system-Annexation #89-8/Placer Road	City of Redding	PG&E		RCLD+15%GCV+ SEV. COSTS	$ 6,128.00	FERC FORM 1 & Redding Elec.	92-02-009	
62	VT	3/2/92	Electric distribution system-Annexation #89-9/Airstrip Road	City of Redding	PG&E		RCLD+15%GCV+ SEV. COSTS	$ 58,849.00	FERC FORM 1 & Redding Elec		
63	VT	3/27/92	Street light system	City of Stockton	PG&E			$ 1,800,000.00	FERC FORM 1		
64	VT	4/10/92	Pole Line-unincorporated area Humboldt County	PG&E	Collins P Mahan			$ 27,874.00	FERC FORM 1		
65	VT	5/10/92	Electric distribution system-Escalon, San Joaquin County	Rich Fruit Psk Co	PG&E			$ 12,668.00	FERC FORM 1		

SUMMARY OF TRANSACTIONS

	TYPE	DATE	DESCRIPTION	BUYER(S)	SELLER(S)	BOOK VALUE	VALUATION METHOD	$ AMOUNT	SOURCE	DEC. NO.	APP. NO.
86	VT	5/10/92	Electric distribution system-Escalon, San Joaquin County	Rich Fruit Pak Co.	PG&E			$ 22,700.00	FERC FORM 1		
87	VT	6/17/92	Electric distribution system-Annexation #89-3, Clear Creek Rd.	City of Redding	PG&E	$ 25,000.00		$ 41,954.00	FERC FORM 1 & Redding Elec	92-06-050	
88	VT	7/27/92	Pole Line-Boonville, Mendocino Co.	PG&E	Anderson Valley TV			$ 3,000.00	FERC FORM 1		
89	VT	8/13/92	Street light system	City of Fresno	PG&E			$ 8,185,068.00	FERC FORM 1		
70	VT	8/28/92	Switch Pole-Potter Valley Mendocino County	Eugene McFadden	PG&E			$ 2,937.00	FERC FORM 1		
71	VT	9/14/92	Pole Line-Creston, San Luis Obispo County	PG&E	Creston Ranch			$ 17,900.00	FERC FORM 1		
72	VT	9/25/92	Street light system	City of Bakersfield	PG&E			$ 2,000,000.00	FERC FORM 1		
73	VT	10/1/92	Electric distribution system	City of San Luis Obispo	PG&E			$ 7,540.00	FERC FORM 1		
74	VT	10/23/92	Electric distribution system-Oakland, Alameda County	Longview Fibre Co.	PG&E			$ 23,500.00	FERC FORM 1		
75	VT	12/8/92	Conduit/Trench-Santa Cruz, Santa Cruz County	United Cable T.V. of Santa Cruz Inc.	PG&E			$ 2,500.00	FERC FORM 1		
78	VT	12/15/92	Electric distribution sytem-Tracy, San Joaquin Co.	Leprino Foods, Inc.	PG&E			$ 101,800.00	FERC FORM 1		
77	VT	12/28/92	Substation, Sunnyvale, Santa Clara County	Signetics Company	PG&E			$ 605,000.00	FERC FORM 1		
78	VT	12/28/92	Substation- Benicia, Solano Co	Exxon Corp	PG&E			$ 30,280.00	FERC FORM 1		
79		12/28/92	Substation- Benicia, Solano Co	Exxon Corp	PG&E			$ 606,400.00	FERC FORM 1		
80	VT	11/26/91	Electric distribution system-Shasta County	City of Redding	PG&E		RCLD+15%GCV+ SEV. COSTS	$ 120,515.00	FERC FORM 1 & Redding Elec		
81	VT	1/25/91	Electric distribution system-Fort Barry,Fort Cronkite-Marin Co	PG&E	Dept. Interior			$ 88,100.00	FERC FORM 1		
82	VT	2/13/91	Electric distribution system-Fall River Mills/Shasta County	PG&E	Fall River Dev			$ 28,990.00	FERC FORM 1		
83	VT	3/28/91	Electric distribution system-San Luis Obispo/SLO County	American Medical International	PG&E			$ 25,000.00	FERC FORM 1		
84	VT	3/29/91	Electric distribution sytem-Annexation #80-11/Oak Mesa	City of Redding	PG&E	$ 10,487.52	RCLD+15%GCV+ SEV. COSTS	$ 42,268.00	FERC FORM 1 & Redding Elec		
85	VT	3/29/91	Electric distribution system-Annexation #88-3/Sheena Lane	City of Redding	PG&E	$ 5,000.00	RCLD+15%GCV+ SEV. COSTS	$ 9,568.00	FERC FORM 1 & Redding Elec		

SUMMARY OF TRANSACTIONS

	TYPE	DATE	DESCRIPTION	BUYER(S)	SELLER(S)	BOOK VALUE	VALUATION METHOD	$ AMOUNT	SOURCE	DEC. NO.	APP. NO.
124	VT	12/31/89	Electric distribution facilities	City of Lodi	PG&E			$ 726.00	FERC FORM 1		
125	VT	12/31/89	Electric distribution facilities	City of Redding	PG&E			$ 335,874.00	FERC FORM 1		
126	VT	12/31/89	Electric distribution facilities	City of Redding	PG&E			$ 423,670.00	FERC FORM 1		
127	VT	12/31/89	Electric distribution facilities	City of Redding	PG&E			$ 153,244.00	FERC FORM 1		
128	VT	12/31/89	Electric distribution facilities	City of Redding	PG&E			$ 33,585.00	FERC FORM 1		
129	VT	12/31/89	Electric distribution facilities	City of Ukiah	PG&E			$ 6,827.00	FERC FORM 1		
130	CC	12/31/89	Electric distribution facilities	SMUD-Rancho Seco	PG&E			$ 655,132.00	FERC FORM 1		
131	VT	12/31/89	Electric distribution facilities	Marin County	PG&E			$ 1,635,259.00	FERC FORM 1		
132	VT	12/31/89	Electric distribution facilities	City of Tosco	PG&E			$ 1,603,469.00	FERC FORM 1		
133	VT	5/10/88	Electric distribution facilities-Plumas & Tehama Counties	PG&E	Lassen Municipal Utility District				FERC FORM 1		
134	VT	5/25/88	Electric distribution facilities Bell Ayne Manor #6	City of Santa Clara	PG&E	$ 9,000.00	RCLD+15% GCV + SEV COSTS	$ 59,834.00 $ 19,873.00	FERC FORM 1	88-05-070	
135	VT	9/14/88	Electric distribution facilities	City of Redding	PG&E	$ 36,000.00	RCLD+15% GCV + SEV COSTS	$ 79,580.00 $ 5,065.00	FERC FORM 1	88-09-039	88-02-034
136	VT	12/31/88	Electric distribution facilities	County of Fresno	PG&E			$ 1,123.00	FERC FORM 1		
137	VT	12/31/88	Electric distribution facilities	City of Napa	PG&E			$ 608,116.00	FERC FORM 1		
138	VT	12/31/88	Electric distribution facilities	City of Newman	PG&E			$ 2,041.00	FERC FORM 1		
139	VT	12/31/88	Electric distribution facilities	City of Roseville	PG&E			$ 170,635.00	FERC FORM 1		
140	VT	12/31/88	Electric distribution facilities	City of Santa Maria	PG&E			$ 30,200.00	FERC FORM 1		
141	VT	12/31/88	Electric distribution facilities	City of Sonoma	PG&E			$ 151,674.00	FERC FORM 1		
142	VT	12/31/88	Electric distribution facilities	City of Tosco	PG&E			$ 311,361.00	FERC FORM 1		
143	VT	12/31/88	Electric distribution facilities	Union Geothermal	PG&E			$ 345.00	FERC FORM 1		
144	VT	1988	Street lights system-So. SF, Daly City,Pacifica,Millbrae, San Mateo Co.	Peninsula Streetlight System	PG&E			$ 1,223,279.00	FERC FORM 1		
145	VT	12/31/87	Electric distribution facilities	County of Fresno	PG&E			$ 5,160.00	FERC FORM 1		
146	VT	12/31/87	Electric distribution facilities	City of Napa	PG&E			$ 1,754.00	FERC FORM 1		
147	VT	12/31/87	Electric distribution facilities	City of Ukiah	PG&E			$ 23,438.00	FERC FORM 1		
148	VT	4/1/88	Street light facilities	City of Napa	PG&E			***	FERC FORM 1	88-02-012	
149	VT	12/31/88	Electric distribution facilities	City of Berkeley	PG&E			$ 11,572.00	FERC FORM 1		

SUMMARY OF TRANSACTIONS

	TYPE	DATE	DESCRIPTION	BUYER(S)	SELLER(S)	BOOK VALUE	VALUATION METHOD	$ AMOUNT	SOURCE	DEC. NO.	APP. NO.
150	V T	12/31/86	Electric distribution facilities	City of Redding	PG&E			$ 184,727.00	FERC FORM 1		
151	VT	12/31/86	Electric distribution facilities	City of Ukiah	PG&E			$ 456.00	FERC FORM 1		
152	VT	1/22/85	Electric distribution facilities-Annexation-Branstetter Ln/Kenyon Rd.	City of Redding	PG&E			***	FERC FORM 1	84-10-050	84-02-06
153	VT	2/8/85	Street light facilities	City of San Mateo	PG&E			***	FERC FORM 1	84-10-058	84-08-012
154	VT	2/11/85	Electric distribution facilities-Annexation-Biggs	City of Biggs	PG&E			***	FERC FORM 1	84-11-084	84-10-018
155	VT	2/13/85	Street light facilities	City of Santa Rosa	PG&E			***	FERC FORM 1	84-10-059	84-08-055
156	CC	3/19/85	Street light facilities	City of Sonoma	PG&E		Unrecovered Historic Investment	$ 104,000.00			
157	VT	5/14/85	Electric distribution facilities-Annexation-Lewis Lane	City of Ukiah	PG&E			***	FERC FORM 1	84-11-016	
158	VT	8/13/85	Electric distribution facilities-Annexation-Airport Industrial Park	City of Ukiah	PG&E			***	FERC FORM 1	84-12-004	84-07-087
159	VT	7/16/85	Electric distribution & street light facilities-Annexation/Enterprise	City of Redding	PG&E			***	FERC FORM 1	85-05-017	
160	VT	8/18/85	Electric distribution facilities-Annexation/Munson-Hastings	City of Ukiah	PG&E			***	FERC FORM 1	84-10-053	
161	VT	9/1/85	Electric distribution facilities-Cantua Creek Housing Project	County of Fresno	PG&E			***	FERC FORM 1	85-05-018	
162	VT	12/31/85	Electric distribution facilities	City of Oakland	PG&E			$ 3,930.00	FERC FORM 1		
163	VT	8/28/84	Electric distribution facilities	City of Redding	PG&E		RCLD+15%GCV+ SEV. COSTS of	$ 376,083.00 $ 2,297.00	FERC FORM 1	84-08-126	83-04-37
164	VT	7/10/84	Street light facilities	Mendota Redevelopment Agency	PG&E & City of Mendota			***	FERC FORM 1	84-03-018	83-12-42
165	VT	2/16/83	Electric distribution system	City of Redding	PG&E			***	FERC FORM 1	83-02-044	82-11-27
166	VT	3/2/83	Electric substation equipment	City & County of San Francisco	PG&E			***	FERC FORM 1	83-03-012	83-01-01
167	VT	6/29/83	Electric street light facilities	City of Arcata	PG&E		RCLD	$ 203,425.58	Dec. & app. filed	83-06-096	83-06-11
168	VT	9/7/83	Electric distribution facilities-Clyde & US Navy @ Port Chicago	PG&E	Bay Point Light & Power Co.	$ 689,000.00	Depreciate Bk Value	$ 685,000.00	Dec. & app. filed & FERC FORM 1	83-09-011	83-01-08
169	VT	4/13/83	Electric distribution facilities	City of Redding	PG&E			***	FERC FORM 1	84-08-126	
170	VT	3/19/82	Electric distribution system	City of Ukiah	PG&E			***	FERC FORM 1	Pending	83-03-12

SUMMARY OF TRANSACTIONS

NOTES & FOOTNOTES

Note * CC = condemnation
** VT = voluntary transaction
*** Dollar amount missing from Ferc Form 1

Footnotes
Transaction # 4 -The $4880 represents the accumulated cost of the pending sale. No journal entries were required to be filed with the commission
Transaction #5 -No journal entries were required to be filed with the commission
Transaction #24 -City of Redding/Hollow Lane--Severance costs covered in a previous sale
Transaction #25 -City of Redding/Collyer Dr. The Ferc Form One shows a total of $44,777.00
Transaction #25 -Severance costs include a "Contributions-in-Aid-of-Construction" (CIAC) tax.
Transaction #58 -City of Healdsburg-Ferc Form One total value was $19,159.00

SUPPLEMENTAL TRANSACTIONS

	TYPE	DATE	DESCRIPTION	BUYER(S)	SELLER(S)	BOOK VALUE	VALUATION METHOD	$ AMOUNT	SOURCE	DEC. NO.	APP. NO.
1	VT	1/20/92	Gas Distribution equipment	U.S. Borax & Chemical Corp.	PG&E			$ 55,600 00	FERC FORM 1		
2	VT	12/30/88	Gas Transmission Facilities-Alameda, San Joaquin, Merced, Fresno Counties	PG&E	Standard Pacific Gas Line, Inc.			***	FERC FORM 1	88-10-028	88-06-036
3	VT	2/15/85	Angels Water System	City of Angels	PG&E			***	FERC FORM 1	84-12-052	84--03-11
4	VT	3/6/85	Western Canal Water System	Western Canal Water District	PG&E			***	FERC FORM 1	84-12-018	84-10-070
5	VT	5/31/84	Amador Water System	Amador County Water Agency	PG&E			***	FERC FORM 1	Pending	
6	VT	12/20/83	Upper Placer Water System	Placer County Water Agency	PG&E			***	FERC FORM 1	83-12-051	83-08-05
7	VT	12/20/83	Tuolumne Water System	Tuolumne Water System	PG&E			***	FERC FORM 1	83-12-064	83-08-13
8	VT	12/5/84	Western Canal Water System	Western Canal Water District	PG&E			***	FERC FORM 1	84-12-018	84-10-070
9	VT	12/5/80	Twolumne Water System-Racetrack Ditch Pipeline	Gibbs Ranch Water Company	PG&E			$ 7,500 00	FERC FORM 1	82-06-013	80-121
10	VT	2/4/81	lease back nuclear fuel for use @ Diablo Canyon Nuclear Power Plt	Pacific Energy Trust	PG&E				FERC FORM 1	92555	60048

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Workpaper
ETAG's Calculation of Net Book Value for PG&E's CCSF Transmission and Distribution Plant
As of December 31, 1981

	(A) Original Cost Alloc. to CCSF	(B) Average Service Life	(C) Average Age	(D) % Depreciated	(E) Accumulated Depreciation	(F) Net Book Value
Transmission Plant						
Land and Land Rights	$0				$0	$0
Structures and Improvements	28,046	44.0	15.0	34%	9,561	18,485
Station Equipment	2,314,016	28.0	8.0	29%	661,147	1,652,869
Towers and Fixtures	0				0	0
Poles and Fixtures	0				0	0
Overhead Conductors and Devices	0				0	0
Underground Conduit	13,438,819	60.0	11.0	18%	2,463,783	10,975,036
Underground Conductors and Devices	7,611,752	32.0	11.0	34%	2,616,540	4,995,212
Roads and Trails	0				0	0
Total Transmission Plant	23,392,633				5,751,032	17,641,601
Distribution Plant						
Land and Land Rights	2,043,896				0	2,043,896
Structures and Improvements	15,441,761	50.0	15.0	30%	4,632,528	10,809,233
Station Equipment	35,125,517	22.0	13.0	59%	20,755,987	14,369,530
Storage Battery Equipment	0				0	0
Poles, Towers and Fixtures	10,894,108	25.0	12.0	48%	5,229,172	5,664,936
Overhead Conductors and Devices	9,446,881	27.0	11.0	41%	3,848,729	5,598,152
Underground Conduit	64,859,238	58.0	9.0	16%	10,064,365	54,794,873
Underground Conductors and Devices	48,448,855	25.0	7.0	28%	13,565,679	34,883,176
Submarine Cables	608,536	30.0	13.0	43%	263,699	344,837
Line Transformers	31,070,347	26.0	12.5	48%	14,937,667	16,132,680
Services	24,540,006	35.8	6.6	18%	4,524,135	20,015,871
Meters	11,352,350	32.0	11.0	34%	3,902,370	7,449,980
Installations on Customer Premises	170,018	36.0	3.0	8%	14,168	155,850
Leased Property on Cust. Premises	5,715	16.0	10.0	63%	3,572	2,143
Street Lighting and Signal Systems	5,816,530	27.0	8.0	30%	1,723,416	4,093,114
Total Distribution Plant	259,823,758				83,465,488	176,358,270
Martin Substation						
Land and Land Rights	38,019				0	38,019
Structures and Improvements	363,853	50.0	27.0	54%	196,481	167,372
Station Equipment	3,014,485	22.0	21.0	95%	2,877,463	137,022
Structures Improvement & Equipment	5,232	50.0	7.0	14%	732	4,500
Control Building Equipment	18,652	28.0	11.0	39%	7,328	11,324
Total Martin Substation	3,440,241				3,082,004	358,237
Total CCSF Plant	$286,656,632				$92,298,524	$194,358,108
Total Customers	307,224					307,224
Avg per Customer	$933					$633

Name of Respondent	This Report is:	Date of Report	Year of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) [X] An Original (2) [ ] A Resubmission	(Mo, Da, Yr)	Dec. 31, 19 81

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Accounts 403, 404, 405)
(Except amortization of acquisition adjustments)

1. Report in Section A for the year the amounts for: (a) *Depreciation Expense* (Account 403); (b) *Amortization of Limited-Term Electric Plant* (Account 404); and (c) *Amortization of Other Electric Plant* (Account 405).

2. Report in section B the rates used to compute amortization charges for electric plant (Accounts 404 and 405). State the basis used to compute the charges and whether any changes have been made in the basis or rates used from the preceding report year.

3. Report all available information called for in section C every fifth year beginning with report year 1971, reporting annually only changes to columns (c) through (g) from the complete report of the preceding year.

Unless composite depreciation accounting for total depreciable plant is followed, list numerically in column (a) each plant subaccount, account or functional classification, as appropriate, to which a rate is applied. Identify at the bottom of section C the type of plant included in any subaccounts used.

In column (b) report all depreciable plant balances to which rates are applied showing subtotals by functional classifications and showing a composite total. Indicate at the bottom of section C the manner in which column (b) balances are obtained. If average balances, state the method of averaging used.

For columns (c), (d), and (e) report available information for each plant subaccount, account or functional classification listed in column (a). If plant mortality studies are prepared to assist in estimating average service lives, show in column (f) the type mortality curve selected as most appropriate for the account and in column (g), if available, the weighted average remaining life of surviving plant.

If composite depreciation accounting is used, report available information called for in columns (b) through (g) on this basis.

4. If provisions for depreciation were made during the year in addition to depreciation provided by application of reported rates, state at the bottom of section C the amounts and nature of the provisions and the plant items to which related.

A. Summary of Depreciation and Amortization Charges

Line No.	Functional Classification (a)	Depreciation Expense (Account 403) (b)	Amortization of Limited-Term Electric Plant (Acct. 404) (c)	Amortization of Other Electric Plant (Acct. 405) (d)	Total (e)
1	Intangible Plant		30,504 (A)		30,504
2	Steam Production Plant	44,354,118			44,354,118
3	Nuclear Production Plant				
4	Hydraulic Production Plant–Conventional	12,766,235			12,766,235
5	Hydraulic Production Plant–Pumped Storage				
6	Other Production Plant	2,741,374			2,741,374
7	Transmission Plant	23,730,019			23,730,019
8	Distribution Plant	125,654,528			125,654,528
9	General Plant	1,991,802			1,991,802
10	Common Plant–Electric	8,797,427			8,797,427
11	TOTAL	220,035,503	30,504		220,066,007

B. Basis for Amortization Charges

(A) Represents costs of storm damage repairs and resulting reinforcement of U.S.B.R. 500 kv line, which are being amortized ratably over the life of the contract which extends to December 31, 2004.

Name of Respondent	This Report Is:	Date of Report	Year of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 1981

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In thousands) (b) *	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rate(s) (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
12	Steam Production-Geothermal						
13	311	43,304	42	-10	2.62	R5	39
14	311	4,534	42	-10	2.66	R5	39
15	312	9,127	35	-10	3.21	R4	31
16	314	174,071	35	0	2.88	R2	32
17	315	29,266	35	0	2.90	R2	32
18	316	3,914	35	5	2.74	R2	32
19	(1)	7,436			2.84		
20		271,652					
21							
22	Steam Production-Other						
23	311	93,514	42	-10	2.92	R5	22
24	311	42,767	42	-10	2.62	R5	40
25	312	613,434	35	-10	3.41	R4	20
26	314	304,569	35	0	2.72	R2	19
27	315	98,701	35	0	2.73	R2	20
28	316	12,998	35	5	2.54	R2	20
29	(1)	17,658			3.10		
30		1,183,641					
31							
32	331	43,262	55	-5	2.13	S3	28
33	331	1,183	55	-5	1.91	S3	53
34	331	201	20	0	4.79	R4	12
35	331	39	20	0	6.66	R4	15
36	332	176,239	95	-15	1.26	R3	70
37	332	270,534	67	-8	1.86	R4	40
38	332	13,061	67	-4	1.82	R4	34
39	332	62,818	67	0	1.54	R4	39
40	332	12,106	67	-10	1.72	R4	44
41	332	1,156	20	0	5.38	R4	11
42	332	2,114	20	0	5.29	R4	11
43	333	104,498	55	-5	1.96	R3	35
44	334	22,856	55	-5	2.01	R3	36
45	335	2,323	40	0	2.13	R2	23
46	336	10,370	55	-10	2.23	R3	31
47	(1)	10,371			1.75		
48		733,131					
49							
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51							
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Name of Respondent	This Report Is:	Date of Report	Year of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) ☒ An Original (2) ☐ A Resubmission	(Mo, Da, Yr)	Dec. 31, 1981

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges (Continued)

Line No.	Account No. (a)	Depreciable Plant Base (In thousands) (b) *	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rate(s) (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)	
64	341	3,688	25	0	4.61	R2	17	
65	341	811	25	0	3.94	R2	22	
66	342	4,892	15	0	6.53	R2	12	
67	343	38	15	0	5.28	R2	7	
68	344	52,452	25	0	3.87	R2	22	
69	345	2,746	15	0	6.83	R2	12	
70	346	91	15	0	7.02	R2	12	
71	(1)	(139)			(4.24)			
72		64,579						
73								
74								
75	352	29,734	44	-5	2.56	L4	28	
76	352	385	44	0	2.37	L4	37	
77	353	338,407	28	25	2.74	L2	16	
78	353	95,079	42	10	2.07	BR. H7	25	
79	354	212,581	57	-5	1.88	R5	40	
80	355	69,838	35	-40	3.89	LO.5	26	
81	356	178,968	50	15	1.43	RO.5	40	
82	356	69,945	40	30	1.52	L2	25	
83	357	26,354	60	0	1.64	R3	49	
84	358	17,977	32	0	3.09	L4	19	
85	359	3,675	37	-15	1.91	BR. HO	20	
86	(1)	14,541			2.24			
87		1,057,484						
88		DISTRIBUTION PLANT						AVG AGE
89	361	STR 46,779	50	0	2.04	BR. H15	35	15
90	361	Sub I 1,676	50	0	2.14	BR. H15	43	7
91	362	S.S 339,071	22	30	2.92	S2	10	12
92	364	Poles 479,624	25	-30	5.59	BR. H3	15	10
93	365	O/H Cond 405,529	27	10	3.41	BR. H2	18	9
94	366	U/G Conduit 245,423	58	-20	2.05	R5	49	9
95	367	U/G Cond 351,240	25	20	3.24	L5	18	7
96	367	1,663	30	10	2.98	R2	19	11
97	368	Line Trans 100,655	25	5	4.25	BR. HO	8	17
98	368	286,379	25	10	3.61	BR. HO	19	6
99	368	62,367	25	20	3.66	BR. HO	19	6
100	368	74,997	25	10	3.60	BR. HO	21	4
101	368	7,255	25	35	2.22	BR. HO	19	6
102	369	SERV 133,902	24	-50	6.73	BR. HO	16	8
103	369	214,682	40	0	2.44	R3	35	5
104	370	METERS 143,115	32	5	2.92	BR. H7	21	11
105	371	4,917	36	0	0.02	S1	31	5
106	372	995	16	75	0.87	S1	9	7
107	373	6,456	23	-30	6.75	BR. HO	13	10
108	373	STR LIGHTS 9,435	40	0	2.27	R3	29	11
109	373	48,154	18	0	6.21	S1	12	6
110	373	19,466	31	0	2.94	BR. H4	23	8
111	373	102	39	0	2.44	R2	10	28
112	(1)	137,068			3.70			
113		3,122,950						
114								
115								

Name of Respondent	This Report Is:	Date of Report (Mo, Da, Yr)	Year of Report
PACIFIC GAS AND ELECTRIC COMPANY	(1) ☒ An Original (2) ☐ A Resubmission		Dec. 31, 1981

DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges (Continued)

Line No.	Account No. (a)	Depreciable Plant Base (In thousands) (b)*	Estimated Avg. Service Life (c)	Net Salvage (Percent) (d)	Applied Depr. Rate(s) (Percent) (e)	Mortality Curve Type (f)	Average Remaining Life (g)
64	390	1	40	5	2.68	R5	23
65	390	10	31	0	3.44	BR. H12	28
66	390	18	31	5	3.27	BR. H12	25
67	390	830	41	0	2.59	BR. H10	33
68	390	2	40	5	2.60	R5	37
69	390	-	33	20	2.56	S6	29
70	390	25	34	0	4.21	R5	16
71	391	54	25	15	3.00	S2	14
72	394	13	31	5	2.76	BR. H12	25
73	395	445	33	20	2.29	S6	25
74	394	12,836	15	5	6.00	R1.5	6
75	396	51	15	10	5.28	R1.5	10
76	397	3,112	23	-10	4.54	R0.5	15
77	398	6,912	40	20	1.37	S1	34
78	(1)	1,039			4.30		
79		25,348					
80	303	1,000	See Page 334 Amortization of Limited Term Electric Plant				
81							
82	TOTAL	6,459,785					
83							
84							
85	(1) Estimated average operative unclassified net additions for 1981.						
86	*Weighted average operative plant for 1981.						
87							
88							
89							
90							
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Workpaper

SF 1981 - Detail per PG&E:

A. Line Transformers WT Avg	$	Wt %	Serv Life	WT Serv Life	Age	WT Age
1.Line Transformers	7,765,443	24.99%	29	7.25	29	7.25
2.OH Line Transformers	5,431,898	17.48%	25	4.37	8	1.40
3.OH Transformer Devices	1,239,537	3.99%	25	1.00	6	0.24
4.UG Line Transformers	9,881,983	31.81%	25	7.95	6	1.91
5.UG Transformer Devices	6,751,486	21.73%	25	5.43	8	1.74
	31,070,347	100.00%		26.00		12.53
Services						
1. OH Services	8,005,092	32.62%	24	7.83	10	3.26
2. UG Services	16,534,914	67.38%	40	26.95	5	3.37
	24,540,006	100.00%		34.78		6.63
Street Lighting						
1.OH Conductors	452,379	7.78%	23	1.79	15	0.14
2 UG Cable and Conduit	1,672,086	28.75%	40	11.50	11	3.31
3.Lamps Arms & Units	2,749,299	47.27%	18	8.51	6	4.02
4.Electroliers	913,247	15.70%	31	4.87	8	0.76
5. Substation Equipment	29,519	0.51%	39	0.20	39	0.00
	5,816,530	100.00%		26.86		8.23

file: Netplant wk4

PG&E Statistics
FERC 1

Workpapers

Accumulated Depreciation	Net Book Value	% Change Net Book	Total System Retail Customers:			% Change	Net Change in NBV - Change in Customers	Net Change in OC - Change in Customers		Avg Age OC/An Depr
1,021,996	2,284,845		1981	3,482,077	$656					
1,117,806	2,378,072		1982	3,528,048	674				1982	
1,226,202	2,461,951	3.53%	1983	3,576,277	688	1.37%	2.16%	4.13%	1983	34.0
1,361,549	2,585,583	5.02%	1984	3,652,073	708	2.12%	2.90%	4.90%	1984	29.2
1,506,126	2,834,749	9.64%	1985	3,724,876	761	1.99%	7.64%	7.98%	1985	30.0
1,690,790	3,121,376	10.11%	1986	3,811,246	819	2.32%	7.79%	8.54%	1986	26.1
1,826,209	3,384,934	8.44%	1987	3,898,922	868	2.30%	6.14%	5.99%	1987	38.5
2,016,785	3,616,899	6.85%	1988	3,982,941	908	2.15%	4.70%	5.95%	1988	29.6
2,220,048	3,959,059	9.46%	1989	4,076,068	971	2.34%	7.12%	7.34%	1989	30.4
2,437,141	4,257,997	7.55%	1990	4,159,209	1,024	2.04%	5.51%	6.31%	1990	30.8
2,642,597	4,596,613	7.95%	1991	4,228,614	1,087	1.67%	6.28%	6.46%	1991	35.2
2,893,988	4,825,018	4.97%	1992	4,275,301	1,129	1.10%	3.86%	5.52%	1992	30.7
3,071,911	4,936,034	2.30%	1993	4,307,165	1,146	0.75%	1.56%	3.00%	1993	45.0
3,313,546	5,059,999	2.51%	1994	4,348,582	1,164	0.96%	1.55%	3.60%	1994	34.7
3,587,139	5,181,674	2.40%	1995	4,387,019	1,181	0.88%	1.52%	3.84%	1995	32.1
	6.17%			1.69%		4.48%	5.64%			

Growth Statistics 1982 Through 1995:	Year End Plant Orginal Cost	Net Additions	Net Adds % Increase
1. Orginal Cost Distrbution Plant ($000)			
1981	3,306,841	274,144	
1982	3,495,878	225,998	6.83%
1983	3,688,153	192,275	5.50%
1984	3,947,132	258,979	7.02%
1985	4,340,875	393,743	9.98%
1986	4,812,166	471,291	10.86%
1987	5,211,143	398,977	8.29%
1988	5,633,684	422,541	8.11%
1989	6,179,107	545,423	9.68%
1990	6,695,138	516,031	8.35%
1991	7,239,210	544,072	8.13%
1992	7,719,006	479,796	6.63%
1993	8,007,945	288,939	3.74%
1994	8,373,545	365,600	4.57%
1995	8,768,813	395,268	4.72%
Total 1982 to 1995		5,272,935	150.83%
COMPOUND ANNUAL GROWTH 1982-1995			7.33%

PG&E Statistics

Total System Retail Customers:		% Change
1982	3,528,048	
1983	3,576,277	1.37%
1984	3,652,073	2.12%
1985	3,724,876	1.99%
1986	3,811,246	2.32%
1987	3,898,922	2.30%
1988	3,982,941	2.15%
1989	4,076,068	2.34%
1990	4,159,209	2.04%
1991	4,228.614	1.67%
1992	4,275,301	1.10%
1993	4,307,165	0.75%
1994	4,348,582	0.96%
1995	4,387,019	0.88%
Total Change 1982 to 1995		24.35%

3. Total Sales MWh	MWh	% Change
1982	56,974,744	
1983	56,753,733	-0.39%
1984	61,195,844	7.83%
1985	63,245,790	3.35%
1986	61,207,439	-3.22%
1987	64,211,884	4.91%
1988	66,681,094	3.85%
1989	68,200,485	2.28%
1990	70,597,825	3.52%
1991	71,039,588	0.63%
1992	71,799,944	1.07%
1993	71,106,363	-0.97%
1994	71,510.177	0.57%
1995	72,321.927	1.14%
Total Change 1982 to 1995		26.94%

600. SALES DATA FOR THE YEAR 1981

STATE OF California

Report below the distribution of customers, sales, and revenue by class of service. *Use a separate sheet for each State in which the respondent operates.* Insert the word "none" opposite any item for which no service is rendered.

Line No.	Class of Service (a)	Average number of customers (b)	Kilowatt-hours (c)	Revenue (show to nearest dollar) (d)	Averages: Kwh Per Customer (e)	Averages: Revenue Per Customer (f)	Averages: Revenue Per Kwh[2] (g)
1	ABC. Rural service [3]			$		$	c.
2	A. Rural residential	855,498	7,360,357,746	414,757,606	8,604	485	5.64
3	B. Irrigation	96,878	3,836,800,499	237,838,883	39,604	2,455	6.20
4	C. All other rural service	125,503	13,722,439,772	748,342,755	109,340	5,963	5.45
5	D. Residential service	2,161,134	12,214,925,348	714,093,659	5,652	330	5.85
6	EF. Commercial service	235,346	13,985,442,721	920,517,992	59,425	3,911	6.58
7	E. Commercial lighting						
8	F. Commercial power						
9	G. Industrial service	535	7,140,240,083	415,513,366	13,346,243	776,660	5.82
10	H. Sales to railroads and railways	1	218,436,940	11,320,340	xxxxxxxxxx	xxxxxxxxxx	5.18
11	I. Public street and highway lighting[1]	7,179	332,645,218	33,484,423	xxxxxxxxxx	xxxxxxxxxx	10.07
12	JK. Other sales to public authorities[1]	3	206,917,053	11,540,425	xxxxxxxxxx	xxxxxxxxxx	5.58
13	J. Municipal pumping[1]				xxxxxxxxxx	xxxxxxxxxx	
14	K. Other public uses[1]				xxxxxxxxxx	xxxxxxxxxx	
15	L. Interdepartmental sales	-	54,921,578	3,621,453	xxxxxxxxxx	xxxxxxxxxx	6.59
16	M. Other sales				xxxxxxxxxx	xxxxxxxxxx	
17	A-M. TOTAL SALES TO ULTIMATE CONSUMERS	3,482,077	59,073,126,958	3,511,030,902	xxxxxxxxxx	xxxxxxxxxx	5.94
18	N. Sales to other electric utilities for resale	15	2,676,998,445	117,791,019	xxxxxxxxxx	xxxxxxxxxx	4.40
19	A-N. TOTAL SALES OF ELECTRIC ENERGY	3,482,092	61,750,125,403	3,628,821,921	xxxxxxxxxx	xxxxxxxxxx	5.88
20	O. Other electric revenues	xxxxxxxxxx	xxxxxxxxxxxxxxxxxxxxxxxx	275,803,182	xxxxxxxxxx	xxxxxxxxxx	-
21	A-O. TOTAL ELECTRIC OPERATING REVENUES	xxxxxxxxxx	xxxxxxxxxxxxxxxxxxxxxxxx	3,904,625,103	xxxxxxxxxx	xxxxxxxxxx	-

[1] Publicly owned respondents will give here all energy furnished under this classification and the revenues actually received. If no revenues are actually received enter the word "free" in the space provided for revenue.

[2] Give in cents per kilowatt-hour the revenue calculated to two decimals, *i.e.*, 3.52 cents.

[3] Includes all unincorporated areas.

file:deprfor.wk4
17-Dec-96

Workpaper
Estimated Net Book Value
PG&E Transmission and Distribution Plant
Serving SF
End of Year 1996

	(A) Original Cost 12-31-96	(B) Accumulated Book Depr 12-31-96	(C) Net Depr Book Value 12-31-96
Transmission Plant			
Land and Land Rights	$0	$0	$0
Structures and Improvements	28,046	19,122	8,924
Station Equipment	3,988,626	2,338,929	1,649,697
Towers and Fixtures	0	0	0
Poles and Fixtures	0	0	0
Overhead Conductors and Devices	0	0	0
Underground Conduit	17,369,071	6,326,632	11,042,439
Underground Conductors and Devices	12,270,143	7,262,976	5,007,167
Roads and Trails	0	0	0
Total Transmission Plant	33,655,886	15,947,659	17,708,227
Distribution Plant			
Land and Land Rights	2,043,896	0	2,043,896
Structures and Improvements	20,997,546	10,111,552	10,885,994
Station Equipment	70,001,245	46,457,916	23,543,329
Storage Battery Equipment	0	0	0
Poles, Towers and Fixtures	23,344,035	14,518,364	8,825,671
Overhead Conductors and Devices	22,410,328	12,615,374	9,794,954
Underground Conduit	86,635,901	29,707,118	56,928,783
Underground Conductors and Devices	97,829,981	56,990,284	40,839,698
Submarine Cables	608,536	567,967	40,569
Line Transformers	92,541,717	48,392,048	44,149,669
Services	57,576,986	20,610,469	36,966,517
Meters	22,084,998	11,702,809	10,382,189
Installations on Customer Premises	170,018	85,009	85,009
Leased Property on Cust. Premises	5,715	5,715	0
Street Lighting and Signal Systems	10,226,238	6,147,326	4,078,912
Total Distribution Plant	506,477,141	257,911,952	248,565,189
Martin Substation			
Land and Land Rights	38,019	0	38,019
Structures and Improvements	494,764	325,583	169,181
Station Equipment	6,007,533	3,987,036	2,020,497
Structures Improvement & Equipment	7,114	2,588	4,526
Control Building Equipment	32,150	20,852	11,298
Total	6,579,580	4,336,059	2,243,521
Total CCSF Plant	$546,712,607	$278,195,669	$268,516,938
Customers	335,628		335,628
Avg Per Customer	$1,629		$800

file:deprfor.wk4
17-Dec-96

Workpaper
Estimated Net Book Value
PG&E Transmission and Distribution Plant
Serving SF
End of Year 2001

Transmission Plant	(A) Original Cost 12-31-01	(B) Accumulated Book Depr 12-31-01	(C) Net Depr Book Value 12-31-01
Land and Land Rights	$0	$0	$0
Structures and Improvements	28,046	19,122	8,924
Station Equipment	4,774,131	3,133,327	1,640,804
Towers and Fixtures	0	0	0
Poles and Fixtures	0	0	0
Overhead Conductors and Devices	0	0	0
Underground Conduit	18,904,242	7,849,946	11,054,296
Underground Conductors and Devices	14,365,272	9,372,477	4,992,795
Roads and Trails	0	0	0
Total Transmission Plant	38,071,691	20,374,872	17,696,819
Distribution Plant			
Land and Land Rights	2,043,896	0	2,043,896
Structures and Improvements	23,239,865	12,344,026	10,895,838
Station Equipment	87,900,339	56,750,971	31,149,369
Storage Battery Equipment	0	0	0
Poles, Towers and Fixtures	29,346,512	17,710,080	11,636,433
Overhead Conductors and Devices	28,512,699	16,080,619	12,432,080
Underground Conduit	95,340,911	33,147,135	62,193,776
Underground Conductors and Devices	121,737,059	77,412,269	44,324,790
Submarine Cables	608,536	567,967	40,569
Line Transformers	121,549,432	63,610,546	57,938,886
Services	72,568,500	26,454,027	46,114,473
Meters	26,972,012	15,247,060	11,724,952
Installations on Customer Premises	170,018	85,009	85,009
Leased Property on Cust. Premises	5,715	5,715	0
Street Lighting and Signal Systems	12,320,411	8,267,984	4,052,427
Total Distribution Plant	622,315,906	327,683,408	294,632,498
Martin Substation			
Land and Land Rights	38,019	0	38,019
Structures and Improvements	547,599	378,201	169,398
Station Equipment	7,543,640	4,870,390	2,673,250
Structures Improvement & Equipment	7,874	3,345	4,529
Control Building Equipment	38,482	24,965	13,516
Total	8,175,614	5,276,901	2,898,713
Total CCSF Plant	$668,563,211	$353,335,181	$315,228,030
Customers	364,038		364,038
Avg Per Customer	$1,837		$866

Electronic wkd 3.3%

Workpapers
Calculation of Reproduction Cost New (RCN)
PG&E's CCSF Transmission and Distribution Plant
Substations and UG Transmission Lines
Year End 1996

1. Calculate Replacement Cost New (RCN) of Transmission Level Substations.

Station Equipment as of Year End 1996

	Station		Total Dollars	Allocated To Account
1.	H	Martin	$18,172,525	Martin Sub Station
2.	X	Mission	7,655,475	Dist Plant-Station Equip.
3.	Z	Embarcadero	14,546,525	Dist Plant-Station Equip.
4.	A	Potrero	7,026,350	Dist Plant-Station Equip.
5.	Y	Larkin	6,944,165	Dist Plant-Station Equip.
6.	W	Bayshore	2,325,550	Dist Plant-Station Equip.
7.	P	Hunters Point	8,682,550	Dist Plant-Station Equip.
	Total Trans Level Substations		$65,353,140	

2. Calculate Replacement Cost New (RCN) of Underground Transmission Lines.

3.50%	Transmission Plant as of Year End 1996		Allocated To Account
	1. Structures and Improvements.	$78,719	
	2. Station Equipment	5,104,984	
	3. Underground Conduit.	32,870,794	
	4. Underground Conductors	18,618,030	
	Total Transmission Plant	$56,672,528	Transmission Plant

3. Calculate Replacement Cost New (RCN) of 9 Sub-transmission Substations.

Station Equipment as of Year End 1996

	Station	Total Dollars	Allocated To Account
1.	J	$1,509,250	
2.	N	1,385,775	
3.	K	1,515,350	
4.	E	1,467,350	
5.	G	1,585,850	
6.	F	1,499,225	
7.	L	1,486,850	
8.	M	1,353,850	
9.	SF Airport	1,560,425	
	Total Sub-Trans Substations	$13,363,925	Dist Plant-Station Equipment

4. Calculate Replacement Cost New (RCN) of 17 Unit Substations 12kv/4kv.

Station Equipment as of Year End 1996		Allocated To Account
Cost per Unit Substation	$788,225	
Number of Unit Substations	17	
Total of 17 Unit Substations	$13,399,825	Dist Plant-Station Equipment

filename wk4 3.5%

Workpapers
Calculation of Reproduction Cost New (RCN)
PG&E's CCSF Transmission and Distribution Plant
Engineering Estimate
Year End 1996

Transmission Plant

Structures and Improvements	$78,719
Station Equipment	5,104,984
Underground Conduit	32,870,794
Underground Conductors and Devices	18,618,030
Total Transmission Plant	56,672,528

Distribution Plant

Land and Land Rights	8,833,601
Structures and Improvements	32,390,137
Station Equipment	73,944,365
Storage Battery Equipment	0
Poles, Towers and Fixtures	48,160,859
Overhead Conductors and Devices	14,322,842
Underground Conduit	108,341,724
Underground Conductors and Devices	132,921,000
Submarine Cables	1,622,257
Line Transformers	75,996,781
Services	209,500,000
Meters	69,325,600
Installations on Customer Premises	315,807
Leased Property on Cust. Premises	13,506
Street Lighting and Signal Systems	14,226,991
Total Distribution Plant	789,915,470

Martin Substation

Land and Land Rights	164,316
Structures and Improvements	1,543,194
Station Equipment - Martin	18,172,525
Structures Improvement & Equipment	11,542
Control Building Equipment	45,622
Total Martin Substation	19,937,200
Total CCSF Plant	$866,525,198
Total Customers	335,628
Avg per Customer	$2,582

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Workpapers
Calculation of Reproduction Cost New Less Depreciation (RCNLD)
PG&E's CCSF Transmission and Distribution Plant
Engineering Estimate - Straight Line Depreciation
Year End 1996

Transmission Plant	(A) RCN	(B) Avg Age Yr End 1996	(C) Service Life	(D) % Depreciated	(E) CCSF RCNLD
Structures and Improvements	$78,719	15	44	34.09%	$51,883
Station Equipment	5,104,984	8	28	28.57%	3,646,417
Underground Conduit	32,870,794	11	60	18.33%	26,844,482
Underground Conductors and Devices	18,618,030	11	32	34.38%	12,218,082
Total Transmission Plant	56,672,528				42,760,865
Distribution Plant					
Land and Land Rights	8,833,601	0	0	0	8,833,601
Structures and Improvements	32,390,137	15	50	30.00%	22,673,096
Station Equipment	73,944,365	13	22	59.09%	30,249,968
Storage Battery Equipment	0	0	0	0.00%	0
Poles, Towers and Fixtures	48,160,859	11	25	44.10%	26,920,090
Overhead Conductors and Devices	14,322,842	10	27	37.45%	8,959,389
Underground Conduit	108,341,724	8	58	14.28%	92,874,916
Underground Conductors and Devices	132,921,000	6	25	25.80%	98,630,306
Submarine Cables	1,622,257	12	30	100.00%	0
Line Transformers	75,996,781	12	26	46.45%	40,697,738
Services	209,500,000	6	36	17.11%	173,652,794
Meters	69,325,600	10	32	31.73%	47,329,887
Installations on Customer Premises	315,807	3	36	8.33%	289,489
Leased Property on Cust. Premises	13,506	10	16	100.00%	0
Street Lighting and Signal Systems	14,226,991	8	27	29.63%	10,011,586
Total Distribution Plant	789,915,470				561,122,860
Martin Substation					
Land and Land Rights	164,316	0	0	0	164,316
Structures and Improvements	1,543,194	27	50	54.00%	709,869
Station Equipment - Martin	18,172,525	21	22	95.45%	826,024
Structures Improvement & Equipment	11,542	7	50	14.00%	9,926
Control Building Equipment	45,622	11	28	39.29%	27,699
Total Martin Substation	19,937,200				1,737,835
Total CCSF Plant	$866,525,198				$605,621,559
		Going Concern Value Adder		15.00%	90,843,234
		Physical Severance			5,000,000
		RCNLD + GCV+ PS			$701,464,793
Total Customers	335,628				335,628
Avg per Customer	$2,582				$2,090

file:rcnld wp4 2.5%

Workpapers
Calculation of Reproduction Cost New Less Depreciation (RCNLD)
PG&E's CCSF Transmission and Distribution Plant
Engineering Estimate - Economic Depreciation
Year End 1996

Transmission Plant	(A) RCN	(B) Avg Age Yr End 1996	(C) Service Life	(D) % Depreciated	(E) CCSF RCNLD
Structures and Improvements	$78,719	15	44	5.09%	$74,709
Station Equipment	5,104,984	8	28	8.76%	4,657,914
Underground Conduit	32,870,794	11	60	0.66%	32,653,670
Underground Conductors and Devices	18,618,030	11	32	9.50%	16,850,072
Total Transmission Plant	56,672,528				54,236,365
Distribution Plant					
Land and Land Rights	8,833,601	0	0	0%	8,833,601
Structures and Improvements	32,390,137	15	50	2.89%	31,455,241
Station Equipment	73,944,365	13	22	34.77%	48,234,319
Storage Battery Equipment	0	0	0	0%	0
Poles, Towers and Fixtures	48,160,859	11	25	22.14%	37,498,454
Overhead Conductors and Devices	14,322,842	10	27	15.65%	12,081,652
Underground Conduit	108,341,724	8	58	0.59%	107,707,506
Underground Conductors and Devices	132,921,000	6	25	9.88%	119,788,521
Submarine Cables	1,622,257	12	30	100.00%	(0)
Line Transformers	75,996,781	12	26	19.97%	60,818,274
Services	209,500,000	6	36	3.31%	202,574,346
Meters	69,325,600	10	32	9.50%	62,742,478
Installations on Customer Premises	315,807	3	36	45.45%	172,270
Leased Property on Cust. Premises	13,506	10	16	100.00%	0
Street Lighting and Signal Systems	14,226,991	8	27	9.69%	12,848,322
Total Distribution Plant	789,915,470				704,754,983
Martin Substation					
Land and Land Rights	164,316	0	0	0	164,316
Structures and Improvements	1,543,194	27	50	10.81%	1,376,328
Station Equipment - Martin	18,172,525	21	22	89.77%	1,859,752
Structures Improvement & Equipment	11,542	7	50	0.87%	11,442
Control Building Equipment	45,622	11	28	14.14%	39,171
Total Martin Substation	19,937,200				3,451,008
Total CCSF Plant	$866,525,198				$762,442,356
		Going Concern Value Adder		15.00%	114,366,353
		Physical Severance			5,000,000
		RCNLD + GCV + PS			$881,808,709
Total Customers	335,628				335,628
Avg per Customer	$2,582				$2,627

Workpapers
Estimated RCNLD Values
PG&E Transmission and Distribution Plant
End of Year 2001

		RCNLD St-Line Depr 12-31-01	RCNLD Sink.-Fund Depr 12-31-01
Transmission Plant			
Land and Land Rights		$0	$0
Structures and Improvements		58,701	84,527
Station Equipment		4,125,586	5,270,002
Towers and Fixtures		0	0
Poles and Fixtures		0	0
Overhead Conductors and Devices		0	0
Underground Conduit		30,372,067	36,944,631
Underground Conductors and Devices		13,823,638	19,064,310
Roads and Trails		0	0
Total Transmission Plant		48,379,994	61,363,469
Distribution Plant			
Land and Land Rights		11,274,162	11,274,162
Structures and Improvements		25,652,527	35,588,718
Station Equipment		34,225,062	54,572,705
Storage Battery Equipment		0	0
Poles, Towers and Fixtures		30,457,611	42,426,058
Overhead Conductors and Devices		10,136,726	13,669,280
Underground Conduit		105,079,442	121,861,157
Underground Conductors and Devices		111,591,139	135,529,717
Submarine Cables		0	(0)
Line Transformers		46,045,755	68,810,294
Services		196,472,198	229,194,278
Meters		53,549,423	70,987,355
Installations on Customer Premises		327,531	194,908
Leased Property on Cust. Premises		0	0
Street Lighting and Signal Systems		11,327,191	14,536,697
Total Distribution Plant		636,138,765	798,645,329
Martin Substation			
Land and Land Rights		209,713	209,713
Structures and Improvements		803,152	1,557,189
Station Equipment		934,570	2,104,138
Structures Improvement & Equipment		11,231	12,946
Control Building Equipment		31,339	44,318
Total Martin Substation		1,990,006	3,928,304
Total CCSF Plant		686,508,764	863,937,102
Going Concern Value Adder	15.00%	102,976,315	129,590,565
Physical Severance		5,000,000	5,000,000
RCNLD + GCV+ PS		$794,485,079	$998,527,667

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Workpapers
Calculation of Reproduction Cost New Less Depreciation (RCNLD)
PG&E's CCSF Generating Stations
Year End 1996

1. RCNLD Using Straight Line Depreciation.

Unit	Nameplate Rating MW	Service Date	Service Life Years	Straight Line % Depreciated	RCN CT Cost $/kW	RCNLD
Hunters Point 4	156	1959	45	82%	$450	$12,480,000
Hunters Point 1	56	1976	30	67%	450	8,400,000
Potrero 3	218	1966	45	67%	450	32,700,000
Potrero 4	67	1976	30	67%	450	10,050,000
Potrero 5	67	1976	30	67%	450	10,050,000
Potrero 6	67	1976	30	67%	450	10,050,000
Total	631					$83,730,000
			Going Concern Value Adder		15.00%	12,559,500
			RCNLD + GCV Adder			$96,289,500

2. RCNLD Using Sinking Fund Depreciation.

Unit	Nameplate Rating MW	Service Date	Service Life Years	Sinking Fund % Depreciated	RCN CT Cost $/kW	RCNLD
Hunters Point 4	156	1959	45	47%	$450	$37,529,736
Hunters Point 1	56	1976	30	35%	450	16,291,939
Potrero 3	218	1966	45	23%	450	75,083,744
Potrero 4	67	1976	30	35%	450	19,492,141
Potrero 5	67	1976	30	35%	450	19,492,141
Potrero 6	67	1976	30	35%	450	19,492,141
Total	631					$187,381,844
			Going Concern Value Adder		15.00%	28,107,277
			RCNLD + GCV Adder			$215,489,120

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Workpapers
Calculation of Reproduction Cost New Less Depreciation (RCNLD)
PG&E's CCSF Generating Stations
Year End 2001

1. RCNLD Using Straight Line Depreciation.

Unit	Nameplate Rating MW	Service Date	Service Life Years	Straight Line % Depreciated	RCN CT Cost $/kW	RCNLD
Hunters Point 4	156	1959	45	93%	$509	$5,294,990
Hunters Point 1	56	1976	30	83%	509	4,751,914
Potrero 3	218	1966	45	78%	509	24,664,699
Potreo 4	67	1976	30	83%	509	5,685,326
Potreo 5	67	1976	30	83%	509	5,685,326
Potreo 6	67	1976	30	83%	509	5,685,326
Total	631					$51,767,583
			Going Concern Value Adder		15.00%	7,765,137
			RCNLD + GCV Adder			$59,532,720

2. RCNLD Using Sinking Fund Depreciation.

Unit	Nameplate Rating MW	Service Date	Service Life Years	Sinking Fund % Depreciated	RCN CT Cost $/kW	RCNLD
Hunters Point 4	156	1959	45	75%	$509	$19,718,729
Hunters Point 1	56	1976	30	60%	509	11,332,145
Potrero 3	218	1966	45	38%	509	68,432,346
Potrero 4	67	1976	30	60%	509	13,558,103
Potrero 5	67	1976	30	60%	509	13,558,103
Potrero 6	67	1976	30	60%	509	13,558,103
Total	631					$140,157,528
			Going Concern Value Adder		15.00%	21,023,629
			RCNLD + GCV Adder			$161,181,157

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Workpapers

CCSF Municipal Forecast
Generating Stations
Plant Staffing and O&M Values
1996 $

	Staffing	Annual Fixed O&M	Variable O&M Mills/kWh
Hunters Point			
Steam Units 2-3-4	74	$13,648,731	1.87
Gas Turbine Unit 1	Remote Operated	279,382	1.24
Total		$13,928,112	
Potrero			
Steam Unit 3	41	5,339,619	1.87
Gas Turbine 4-5-6	Remote Operated	683,538	1.24
Total		6,023,157	
Total All Generation		$19,951,269	

Sinking Fund T	9.80%									
Life:	1	2	3	4	5	6	7	8	9	10
16	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83	2.83
Cumm Balance	2.83	2.83	5.94	9.35	13.09	17.21	21.72	26.68	32.13	38.11
Interest	0	0.28	0.58	0.92	1.28	1.69	2.13	2.61	3.15	3.73
Balance w/Int	**2.83**	**5.937**	**9.349**	**13.095**	**17.208**	**21.724**	**26.683**	**32.127**	**38.106**	**44.670**
Life:										
22	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44
Cumm Balance	1.44	1.44	3.01	4.75	6.65	8.74	11.03	13.55	16.31	19.35
Interest	0	0.14	0.30	0.47	0.65	0.86	1.08	1.33	1.60	1.90
Balance w/Int	**1.44**	**3.014**	**4.747**	**6.648**	**8.737**	**11.030**	**13.548**	**16.312**	**19.347**	**22.680**
Life:	1	2	3	4	5	6	7	8	9	10
23	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29
Cumm Balance	1.29	1.29	2.71	4.27	5.98	7.85	9.92	12.18	14.66	17.39
Interest	0	0.13	0.27	0.42	0.59	0.77	0.97	1.19	1.44	1.70
Balance w/Int	**1.29**	**2.710**	**4.267**	**5.977**	**7.854**	**9.916**	**12.179**	**14.664**	**17.393**	**20.389**
Life:										
25	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05
Cumm Balance	1.05	1.05	2.20	3.46	4.85	6.37	8.04	9.88	11.90	14.11
Interest	0	0.10	0.22	0.34	0.48	0.62	0.79	0.97	1.17	1.38
Balance w/Int	**1.05**	**2.198**	**3.462**	**4.849**	**6.372**	**8.044**	**9.880**	**11.896**	**14.110**	**16.540**
Life:										
26	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Cumm Balance	0.95	0.95	1.98	3.12	4.37	5.75	7.26	8.91	10.73	12.73
Interest	0	0.09	0.19	0.31	0.43	0.56	0.71	0.87	1.05	1.25
Balance w/Int	**0.95**	**1.983**	**3.123**	**4.374**	**5.748**	**7.257**	**8.913**	**10.732**	**12.729**	**14.921**
Life:										
27	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Cumm Balance	0.85	0.85	1.79	2.82	3.95	5.19	6.55	8.05	9.69	11.49
Interest	0	0.08	0.18	0.28	0.39	0.51	0.64	0.79	0.95	1.13
Balance w/Int	**0.85**	**1.791**	**2.820**	**3.950**	**5.190**	**6.553**	**8.048**	**9.691**	**11.494**	**13.474**
Life:										
28	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77
Cumm Balance	0.77	0.77	1.62	2.55	3.57	4.69	5.92	7.27	8.76	10.39
Interest	0	0.08	0.16	0.25	0.35	0.46	0.58	0.71	0.86	1.02
Balance w/Int	**0.77**	**1.618**	**2.548**	**3.569**	**4.691**	**5.922**	**7.273**	**8.758**	**10.387**	**12.176**
Life:	1	2	3	4	5	6	7	8	9	10
30	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63
Cumm Balance	0.63	0.63	1.32	2.09	2.92	3.84	4.85	5.95	7.17	8.50
Interest	0	0.06	0.13	0.20	0.29	0.38	0.47	0.58	0.70	0.83
Balance w/Int	**0.63**	**1.325**	**2.086**	**2.921**	**3.839**	**4.847**	**5.953**	**7.168**	**8.502**	**9.966**
32	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
Cumm Balance	0.52	0.52	1.09	1.71	2.40	3.15	3.98	4.88	5.88	6.98
Interest	0	0.05	0.11	0.17	0.23	0.31	0.39	0.48	0.58	0.68
Balance w/Int	**0.52**	**1.087**	**1.711**	**2.397**	**3.150**	**3.976**	**4.884**	**5.881**	**6.975**	**8.177**
Life:										
36	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
Cumm Balance	0.35	0.35	0.74	1.16	1.62	2.13	2.69	3.31	3.98	4.72
Interest	0	0.03	0.07	0.11	0.16	0.21	0.26	0.32	0.39	0.46
Balance w/Int	**0.35**	**0.736**	**1.158**	**1.622**	**2.132**	**2.691**	**3.306**	**3.980**	**4.721**	**5.534**

Sinking Fund T 9.80%

Life:	1	2	3	4	5	6	7	8	9	10
44	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Cumm Balance	0.16	0.16	0.34	0.54	0.75	0.99	1.25	1.54	1.85	2.19
Interest	0	0.02	0.03	0.05	0.07	0.10	0.12	0.15	0.18	0.21
Balance w/Int	**0.16**	**0.342**	**0.538**	**0.754**	**0.990**	**1.250**	**1.536**	**1.849**	**2.193**	**2.571**
Life:	1	2	3	4	5	6	7	8	9	10
50	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Cumm Balance	0.09	0.09	0.19	0.30	0.43	0.56	0.71	0.87	1.05	1.24
Interest	0	0.01	0.02	0.03	0.04	0.06	0.07	0.09	0.10	0.12
Balance w/Int	**0.09**	**0.194**	**0.305**	**0.427**	**0.561**	**0.709**	**0.870**	**1.048**	**1.243**	**1.457**
58	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Cumm Balance	0.04	0.04	0.09	0.14	0.20	0.26	0.33	0.41	0.49	0.59
Interest	0	0.00	0.01	0.01	0.02	0.03	0.03	0.04	0.05	0.06
Balance w/Int	**0.04**	**0.091**	**0.144**	**0.201**	**0.264**	**0.334**	**0.410**	**0.494**	**0.585**	**0.686**
60	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Cumm Balance	0.04	0.04	0.08	0.12	0.17	0.22	0.28	0.34	0.41	0.49
Interest	0	0.00	0.01	0.01	0.02	0.02	0.03	0.03	0.04	0.05
Balance w/Int	**0.04**	**0.076**	**0.119**	**0.167**	**0.219**	**0.277**	**0.340**	**0.409**	**0.485**	**0.569**
45	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Cumm Balance	0.15	0.15	0.31	0.49	0.69	0.90	1.14	1.40	1.68	1.99
Interest	0	0.01	0.03	0.05	0.07	0.09	0.11	0.14	0.16	0.20
Balance w/Int	**0.15**	**0.311**	**0.489**	**0.685**	**0.901**	**1.137**	**1.397**	**1.682**	**1.995**	**2.338**

Sinking Fund T

Life:	11	12	13	14	15	16	17	18	19	20
16	2.83	2.83	2.83	2.83	2.83	2.83				
Cumm Balance	44.67	51.88	59.79	68.48	78.02	88.50				
Interest	4.38	5.08	5.86	6.71	7.65	8.67				
Balance w/Int	**51.877**	**59.791**	**68.481**	**78.021**	**88.497**	**100.000**				
Life:										
22	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44	1.44
Cumm Balance	22.68	26.34	30.36	34.77	39.61	44.93	50.77	57.19	64.23	71.96
Interest	2.22	2.58	2.98	3.41	3.88	4.40	4.98	5.60	6.29	7.05
Balance w/Int	**26.340**	**30.358**	**34.769**	**39.614**	**44.933**	**50.773**	**57.185**	**64.226**	**71.957**	**80.446**
Life:	11	12	13	14	15	16	17	18	19	20
23	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29	1.29
Cumm Balance	20.39	23.68	27.29	31.26	35.61	40.39	45.64	51.41	57.74	64.69
Interest	2.00	2.32	2.67	3.06	3.49	3.96	4.47	5.04	5.66	6.34
Balance w/Int	**23.679**	**27.291**	**31.257**	**35.612**	**40.394**	**45.644**	**51.409**	**57.738**	**64.688**	**72.319**
Life:										
25	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05	1.05
Cumm Balance	16.54	19.21	22.14	25.36	28.89	32.77	37.03	41.70	46.84	52.48
Interest	1.62	1.88	2.17	2.48	2.83	3.21	3.63	4.09	4.59	5.14
Balance w/Int	**19.209**	**22.139**	**25.357**	**28.889**	**32.768**	**37.027**	**41.704**	**46.839**	**52.477**	**58.667**
Life:										
26	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95	0.95
Cumm Balance	14.92	17.33	19.97	22.88	26.06	29.56	33.40	37.62	42.26	47.34
Interest	1.46	1.70	1.96	2.24	2.55	2.90	3.27	3.69	4.14	4.64
Balance w/Int	**17.329**	**19.973**	**22.875**	**26.062**	**29.562**	**33.404**	**37.623**	**42.255**	**47.341**	**52.926**
Life:										
27	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85	0.85
Cumm Balance	13.47	15.65	18.03	20.66	23.53	26.69	30.16	33.97	38.16	42.75
Interest	1.32	1.53	1.77	2.02	2.31	2.62	2.96	3.33	3.74	4.19
Balance w/Int	**15.648**	**18.035**	**20.656**	**23.533**	**26.693**	**30.163**	**33.972**	**38.155**	**42.748**	**47.791**
Life:										
28	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77
Cumm Balance	12.18	14.14	16.30	18.67	21.27	24.12	27.26	30.70	34.48	38.63
Interest	1.19	1.39	1.60	1.83	2.08	2.36	2.67	3.01	3.38	3.79
Balance w/Int	**14.141**	**16.298**	**18.667**	**21.268**	**24.123**	**27.259**	**30.701**	**34.482**	**38.632**	**43.190**
Life:	11	12	13	14	15	16	17	18	19	20
30	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63
Cumm Balance	9.97	11.57	13.34	15.28	17.41	19.74	22.31	25.13	28.22	31.62
Interest	0.98	1.13	1.31	1.50	1.71	1.93	2.19	2.46	2.77	3.10
Balance w/Int	**11.574**	**13.340**	**15.278**	**17.407**	**19.744**	**22.311**	**25.128**	**28.222**	**31.619**	**35.349**
32	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
Cumm Balance	8.18	9.50	10.94	12.54	14.28	16.20	18.30	20.62	23.15	25.94
Interest	0.80	0.93	1.07	1.23	1.40	1.59	1.79	2.02	2.27	2.54
Balance w/Int	**9.496**	**10.945**	**12.535**	**14.282**	**16.199**	**18.305**	**20.616**	**23.155**	**25.942**	**29.002**
Life:										
36	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
Cumm Balance	5.53	6.43	7.41	8.48	9.67	10.96	12.39	13.95	15.67	17.56
Interest	0.54	0.63	0.73	0.83	0.95	1.07	1.21	1.37	1.54	1.72
Balance w/Int	**6.427**	**7.408**	**8.484**	**9.666**	**10.964**	**12.389**	**13.954**	**15.672**	**17.559**	**19.630**

Sinking Fund T

Life:	11	12	13	14	15	16	17	18	19	20
44	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Cumm Balance	2.57	2.99	3.44	3.94	4.49	5.09	5.76	6.48	7.28	8.16
Interest	0.25	0.29	0.34	0.39	0.44	0.50	0.56	0.64	0.71	0.80
Balance w/Int	**2.986**	**3.442**	**3.942**	**4.491**	**5.094**	**5.756**	**6.483**	**7.281**	**8.158**	**9.120**
Life:	11	12	13	14	15	16	17	18	19	20
50	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Cumm Balance	1.46	1.69	1.95	2.23	2.54	2.89	3.26	3.67	4.13	4.62
Interest	0.14	0.17	0.19	0.22	0.25	0.28	0.32	0.36	0.40	0.45
Balance w/Int	**1.692**	**1.950**	**2.234**	**2.545**	**2.886**	**3.262**	**3.673**	**4.126**	**4.622**	**5.168**
58	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Cumm Balance	0.69	0.80	0.92	1.05	1.20	1.36	1.54	1.73	1.94	2.18
Interest	0.07	0.08	0.09	0.10	0.12	0.13	0.15	0.17	0.19	0.21
Balance w/Int	**0.797**	**0.919**	**1.052**	**1.199**	**1.360**	**1.536**	**1.730**	**1.943**	**2.177**	**2.434**
60	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Cumm Balance	0.57	0.66	0.76	0.87	0.99	1.13	1.27	1.43	1.61	1.80
Interest	0.06	0.06	0.07	0.09	0.10	0.11	0.12	0.14	0.16	0.18
Balance w/Int	**0.661**	**0.761**	**0.872**	**0.993**	**1.127**	**1.273**	**1.434**	**1.611**	**1.805**	**2.017**
45	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Cumm Balance	2.34	2.72	3.13	3.58	4.08	4.63	5.23	5.90	6.62	7.42
Interest	0.23	0.27	0.31	0.35	0.40	0.45	0.51	0.58	0.65	0.73
Balance w/Int	**2.716**	**3.130**	**3.585**	**4.084**	**4.632**	**5.235**	**5.896**	**6.622**	**7.419**	**8.294**

Sinking Fund T

Life:	21	22	23	24	25	26	27	28	29	30
16										
Cumm Balance										
Interest										
Balance w/Int										
Life:										
22	1.44	1.44								
Cumm Balance	80.45	89.77								
Interest	7.88	8.80								
Balance w/Int	**89.766**	**100.000**								
Life:	21	22	23	24	25	26	27	28	29	30
23	1.29	1.29	1.29							
Cumm Balance	72.32	80.70	89.90							
Interest	7.09	7.91	8.81							
Balance w/Int	**80.698**	**89.898**	**100.000**							
Life:										
25	1.05	1.05	1.05	1.05	1.05					
Cumm Balance	58.67	65.46	72.93	81.12	90.12					
Interest	5.75	6.42	7.15	7.95	8.83					
Balance w/Int	**65.464**	**72.928**	**81.123**	**90.120**	**100.000**					
Life:										
26	0.95	0.95	0.95	0.95	0.95	0.95				
Cumm Balance	52.93	59.06	65.79	73.18	81.30	90.21				
Interest	5.19	5.79	6.45	7.17	7.97	8.84				
Balance w/Int	**59.058**	**65.791**	**73.184**	**81.301**	**90.214**	**100.000**				
Life:										
27	0.85	0.85	0.85	0.85	0.85	0.85	0.85			
Cumm Balance	47.79	53.33	59.41	66.08	73.41	81.46	90.30			
Interest	4.68	5.23	5.82	6.48	7.19	7.98	8.85			
Balance w/Int	**53.328**	**59.407**	**66.083**	**73.413**	**81.461**	**90.297**	**100.000**			
Life:										
28	0.77	0.77	0.77	0.77	0.77	0.77	0.77	0.77		
Cumm Balance	43.19	48.19	53.69	59.72	66.34	73.62	81.60	90.37		
Interest	4.23	4.72	5.26	5.85	6.50	7.21	8.00	8.86		
Balance w/Int	**48.193**	**53.688**	**59.721**	**66.345**	**73.618**	**81.604**	**90.372**	**100.000**		
Life:	21	22	23	24	25	26	27	28	29	30
30	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63	0.63
Cumm Balance	35.35	39.45	43.94	48.88	54.30	60.25	66.79	73.97	81.85	90.50
Interest	3.46	3.87	4.31	4.79	5.32	5.90	6.55	7.25	8.02	8.87
Balance w/Int	**39.445**	**43.942**	**48.880**	**54.301**	**60.254**	**66.790**	**73.967**	**81.847**	**90.500**	**100.000**
32	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52	0.52
Cumm Balance	29.00	32.36	36.05	40.10	44.55	49.44	54.80	60.69	67.15	74.25
Interest	2.84	3.17	3.53	3.93	4.37	4.84	5.37	5.95	6.58	7.28
Balance w/Int	**32.363**	**36.052**	**40.103**	**44.551**	**49.435**	**54.798**	**60.686**	**67.151**	**74.250**	**82.045**
Life:										
36	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35	0.35
Cumm Balance	19.63	21.90	24.40	27.14	30.15	33.46	37.09	41.07	45.45	50.26
Interest	1.92	2.15	2.39	2.66	2.96	3.28	3.63	4.03	4.45	4.93
Balance w/Int	**21.904**	**24.402**	**27.143**	**30.154**	**33.460**	**37.089**	**41.075**	**45.451**	**50.256**	**55.531**

Sinking Fund T

Life:	21	22	23	24	25	26	27	28	29	30
44	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Cumm Balance	9.12	10.18	11.34	12.61	14.01	15.55	17.23	19.08	21.12	23.35
Interest	0.89	1.00	1.11	1.24	1.37	1.52	1.69	1.87	2.07	2.29
Balance w/Int	**10.177**	**11.337**	**12.611**	**14.009**	**15.545**	**17.232**	**19.083**	**21.116**	**23.348**	**25.800**
Life:	21	22	23	24	25	26	27	28	29	30
50	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Cumm Balance	5.17	5.77	6.42	7.15	7.94	8.81	9.76	10.81	11.97	13.23
Interest	0.51	0.57	0.63	0.70	0.78	0.86	0.96	1.06	1.17	1.30
Balance w/Int	**5.766**	**6.424**	**7.146**	**7.938**	**8.808**	**9.764**	**10.813**	**11.965**	**13.230**	**14.619**
58	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Cumm Balance	2.43	2.72	3.03	3.37	3.74	4.15	4.60	5.09	5.64	6.23
Interest	0.24	0.27	0.30	0.33	0.37	0.41	0.45	0.50	0.55	0.61
Balance w/Int	**2.716**	**3.026**	**3.366**	**3.739**	**4.149**	**4.599**	**5.093**	**5.636**	**6.231**	**6.886**
60	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Cumm Balance	2.02	2.25	2.51	2.79	3.10	3.44	3.81	4.22	4.67	5.16
Interest	0.20	0.22	0.25	0.27	0.30	0.34	0.37	0.41	0.46	0.51
Balance w/Int	**2.251**	**2.508**	**2.790**	**3.099**	**3.439**	**3.812**	**4.221**	**4.671**	**5.165**	**5.707**
45	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Cumm Balance	8.29	9.25	10.31	11.47	12.74	14.14	15.67	17.35	19.20	21.23
Interest	0.81	0.91	1.01	1.12	1.25	1.39	1.54	1.70	1.88	2.08
Balance w/Int	**9.255**	**10.310**	**11.468**	**12.740**	**14.137**	**15.670**	**17.354**	**19.203**	**21.233**	**23.462**

Sinking Fund T										
Life:	31	32	33	34	35	36	37	38	39	40
16										
Cumm Balance										
Interest										
Balance w/Int										
Life:										
22										
Cumm Balance										
Interest										
Balance w/Int										
Life:	31	32	33	34	35	36	37	38	39	40
23										
Cumm Balance										
Interest										
Balance w/Int										
Life:										
25										
Cumm Balance										
Interest										
Balance w/Int										
Life:										
26										
Cumm Balance										
Interest										
Balance w/Int										
Life:										
27										
Cumm Balance										
Interest										
Balance w/Int										
Life:										
28										
Cumm Balance										
Interest										
Balance w/Int										
Life:	31	32	33	34	35	36	37	38	39	40
30										
Cumm Balance										
Interest										
Balance w/Int										
32	0.52	0.52								
Cumm Balance	82.04	90.60								
Interest	8.04	8.88								
Balance w/Int	**90.603**	**100.000**								
Life:										
36	0.35	0.35	0.35	0.35	0.35	0.35				
Cumm Balance	55.53	61.32	67.68	74.67	82.34	90.76				
Interest	5.44	6.01	6.63	7.32	8.07	8.89				
Balance w/Int	**61.324**	**67.684**	**74.668**	**82.336**	**90.755**	**100.000**				

Sinking Fund T

Life:	31	32	33	34	35	36	37	38	39	40
44	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16	0.16
Cumm Balance	25.80	28.49	31.45	34.69	38.25	42.16	46.46	51.18	56.35	62.04
Interest	2.53	2.79	3.08	3.40	3.75	4.13	4.55	5.02	5.52	6.08
Balance w/Int	**28.491**	**31.446**	**34.690**	**38.253**	**42.165**	**46.460**	**51.175**	**56.354**	**62.039**	**68.282**
Life:	31	32	33	34	35	36	37	38	39	40
50	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09	0.09
Cumm Balance	14.62	16.14	17.82	19.66	21.68	23.89	26.33	29.00	31.93	35.15
Interest	1.43	1.58	1.75	1.93	2.12	2.34	2.58	2.84	3.13	3.44
Balance w/Int	**16.144**	**17.818**	**19.657**	**21.675**	**23.892**	**26.325**	**28.997**	**31.931**	**35.153**	**38.690**
58	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Cumm Balance	6.89	7.60	8.39	9.26	10.21	11.25	12.40	13.66	15.04	16.56
Interest	0.67	0.75	0.82	0.91	1.00	1.10	1.22	1.34	1.47	1.62
Balance w/Int	**7.604**	**8.393**	**9.258**	**10.209**	**11.253**	**12.400**	**13.658**	**15.040**	**16.558**	**18.224**
60	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04	0.04
Cumm Balance	5.71	6.30	6.96	7.67	8.46	9.33	10.28	11.32	12.47	13.72
Interest	0.56	0.62	0.68	0.75	0.83	0.91	1.01	1.11	1.22	1.34
Balance w/Int	**6.302**	**6.956**	**7.674**	**8.462**	**9.327**	**10.277**	**11.320**	**12.466**	**13.723**	**15.104**
45	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15	0.15
Cumm Balance	23.46	25.91	28.60	31.55	34.79	38.34	42.25	46.54	51.25	56.42
Interest	2.30	2.54	2.80	3.09	3.41	3.76	4.14	4.56	5.02	5.53
Balance w/Int	**25.909**	**28.597**	**31.547**	**34.787**	**38.344**	**42.250**	**46.539**	**51.248**	**56.418**	**62.095**

Sinking Fund T					
Life:	41	42	43	44	45
16					
Cumm Balance					
Interest					
Balance w/Int					
Life:					
22					
Cumm Balance					
Interest					
Balance w/Int					
Life:	41	42	43	44	45
23					
Cumm Balance					
Interest					
Balance w/Int					
Life:					
25					
Cumm Balance					
Interest					
Balance w/Int					
Life:					
26					
Cumm Balance					
Interest					
Balance w/Int					
Life:					
27					
Cumm Balance					
Interest					
Balance w/Int					
Life:					
28					
Cumm Balance					
Interest					
Balance w/Int					
Life:	41	42	43	44	45
30					
Cumm Balance					
Interest					
Balance w/Int					
32					
Cumm Balance					
Interest					
Balance w/Int					
Life:					
36					
Cumm Balance					
Interest					
Balance w/Int					

Sinking Fund T

Life:	41	42	43	44	45
44	0.16	0.16	0.16	0.16	
Cumm Balance	68.28	75.14	82.66	90.93	
Interest	6.69	7.36	8.10	8.91	
Balance w/Int	**75.136**	**82.663**	**90.926**	**100.000**	
Life:	41	42	43	44	45
50	0.09	0.09	0.09	0.09	0.09
Cumm Balance	38.69	42.57	46.84	51.52	56.66
Interest	3.79	4.17	4.59	5.05	5.55
Balance w/Int	**42.574**	**46.839**	**51.521**	**56.663**	**62.308**
58	0.04	0.04	0.04	0.04	0.04
Cumm Balance	18.22	20.05	22.06	24.27	26.69
Interest	1.79	1.97	2.16	2.38	2.62
Balance w/Int	**20.053**	**22.062**	**24.267**	**26.689**	**29.348**
60	0.04	0.04	0.04	0.04	0.04
Cumm Balance	15.10	16.62	18.29	20.11	22.12
Interest	1.48	1.63	1.79	1.97	2.17
Balance w/Int	**16.621**	**18.285**	**20.113**	**22.121**	**24.324**
45	0.15	0.15	0.15	0.15	0.15
Cumm Balance	62.10	68.33	75.17	82.69	90.94
Interest	6.09	6.70	7.37	8.10	8.91
Balance w/Int	**68.329**	**75.173**	**82.688**	**90.940**	**100.000**

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Workpaper
Annual Depreciation Expense
CCSF Transmission and Distribution Plant
Based on Net Book Value
2002 Through 2011

Transmission Plant	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Land and Land Rights										
Structures and Improvements	637	637	637	637	637	637	637	637	637	637
Station Equipment	94,103	100,573	107,280	114,233	121,440	128,911	136,655	144,683	149,950	155,409
Towers and Fixtures										
Poles and Fixtures										
Overhead Conductors and Devices										
Underground Conduit	320,453	325,928	331,495	337,159	342,918	348,777	354,735	360,795	366,958	373,227
Underground Conductors and Devices	463,294	240,267	255,582	271,388	287,700	304,534	321,908	339,838	358,343	377,440
Roads and Trails										
Total Transmission Plant	878,488	667,405	694,995	723,416	752,695	782,859	813,935	845,954	875,889	906,714
Distribution Plant										
Land and Land Rights										
Structures and Improvements	474,326	175,214	185,137	195,264	205,598	216,143	232,959	243,942	255,150	266,587
Station Equipment	2,585,008	2,779,834	2,908,623	3,043,378	3,184,377	3,331,907	3,486,271	3,647,786	3,816,784	3,993,610
Storage Battery Equipment										
Poles, Towers and Fixtures	791,947	847,923	906,109	966,592	1,029,464	1,094,820	1,162,757	1,208,446	1,255,938	1,305,304
Overhead Conductors and Devices	778,538	834,845	893,216	953,727	1,016,457	1,081,486	1,148,900	1,194,239	1,241,236	1,289,953
Underground Conduit	557,358	589,791	622,863	656,588	690,979	726,052	761,819	776,493	791,472	806,762
Underground Conductors and Devices	3,146,320	3,369,701	3,602,015	3,843,621	4,094,891	4,356,213	4,529,522	4,709,746	4,897,162	5,092,058
Submarine Cables	20,285	20,285	20,285	20,285	20,285	20,285	20,285	20,285	20,285	20,285
Line Transformers	3,782,903	4,050,727	4,328,416	4,616,334	4,914,860	5,224,385	5,424,511	5,632,009	5,847,150	6,070,217
Services	1,433,697	1,528,814	1,627,033	1,728,456	1,833,189	1,941,340	2,004,330	2,069,383	2,136,569	2,205,957
Meters	521,763	556,521	592,430	629,527	667,853	707,448	730,750	750,336	775,201	800,888
Installations on Customer Premises	4,723	4,723	4,723	4,723	4,723	4,723	4,723	4,723	4,723	4,723
Leased Property on Cust. Premises	357	357	357	357	357	357	357	357	357	357
Street Lighting and Signal Systems	258,207	276,188	294,851	314,223	334,330	355,200	376,863	391,090	405,854	421,176
Total Distribution Plant	14,355,432	15,034,922	15,986,057	16,973,075	17,997,361	19,060,359	19,884,048	20,648,835	21,447,880	22,277,877
Martin Substation										
Land and Land Rights										
Structures and Improvements	3,905	4,136	4,370	4,610	4,854	5,104	5,359	5,468	5,579	5,693
Station Equipment	221,846	238,566	256,065	267,933	280,351	293,345	306,941	321,167	336,052	351,626
Structures Improvement & Equipment	56	59	63	64	65	67	68	69	71	72
Control Building Equipment	637	666	696	728	760	794	829	841	853	865
Total	226,445	243,427	261,195	273,335	286,031	299,310	313,196	327,544	342,554	358,256
Total Annual Depreciation	$15,460,365	$15,945,755	$16,942,247	$17,969,826	$19,036,088	$20,142,527	$21,011,179	$21,822,332	$22,666,323	$23,542,847

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Workpaper

Investment in Assets All Cases

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
NBV Case										
1 Orginal Cost	$667,903,073	$700,019,179	$728,131,945	$757,279,533	$787,501,609	$818,839,404	$851,335,775	$885,035,271	$919,984,201	$956,230,706
2 Capital Additions	32,116,107	28,112,766	29,147,588	30,222,076	31,337,795	32,496,371	33,699,496	34,948,930	36,246,505	37,594,127
3 Total Orignal Cost	700,019,179	728,131,945	757,279,533	787,501,609	818,839,404	851,335,775	885,035,271	919,984,201	956,230,706	993,824,833
4 Annual Depr	15,434,363	15,919,753	16,916,245	17,943,824	19,010,086	20,116,525	20,985,177	21,796,330	22,640,321	23,516,845
5 Cummulative Depr	368,091,731	384,011,483	400,927,729	418,871,553	437,881,639	457,998,165	478,983,342	500,779,673	523,419,994	546,936,839
6 Net Book Value	331,927,449	344,120,462	356,351,804	368,630,056	380,957,765	393,337,610	406,051,928	419,204,528	432,810,712	446,887,994
PG&E Avg System Alloc to CCSF									5 Year Trend	0.024
PG&E Avg System NBV Alloc to CCSF	480,834,911	493,384,947	505,989,151	518,651,599	531,376,340	544,167,592	557,029,711	569,967,189	582,984,663	596,939,220
									5 Year Trend	0.027
PG&E Annual Depr Allocated to CCSF	25,609,351	26,482,476	27,375,319	28,288,346	29,222,036	30,176,878	31,153,375	32,152,043	33,173,410	33,365,707
RCNLD-SL :	1	2	3	4	5	6	7	8	9	10
1 RCNLD-SL BOY	$794,485,079	821,601,186	849,713,952	878,861,539	909,083,615	940,421,411	972,917,781	1,006,617,277	1,041,566,207	1,077,812,713
2 Capital Adds from NBV Case (Less PS)	27,116,107	28,112,766	29,147,588	30,222,076	31,337,795	32,496,371	33,699,496	34,948,930	36,246,505	37,594,127
3 RCNLD-SL EOY	821,601,186	849,713,952	878,861,539	909,083,615	940,421,411	972,917,781	1,006,617,277	1,041,566,207	1,077,812,713	1,115,406,840
4 Annual Depr NBV Case	15,434,363	15,919,753	16,916,245	17,943,824	19,010,086	20,116,525	20,985,177	21,796,330	22,640,321	23,516,845
5 SL Amortization of Diff (NBV v RCNLD) 20 yrs	23,977,852	23,977,852	23,977,852	23,977,852	23,977,852	23,977,852	23,977,852	23,977,852	23,977,852	23,977,852
6 Total Annual Depr & Amortization	39,412,215	39,897,605	40,894,098	41,921,677	42,987,939	44,094,378	44,963,030	45,774,183	46,618,174	47,494,698
7 Cummulative Depr & Amortization	39,412,215	79,309,820	120,203,918	162,125,595	205,113,534	249,207,912	294,170,942	339,945,125	386,563,298	434,057,996
8 Net Book Value	782,188,971	770,404,131	758,657,621	746,958,020	735,307,877	723,709,870	712,446,336	701,621,083	691,249,414	681,348,844
What if 30 Amortization - NBV	790,181,588	786,389,366	782,635,473	778,928,490	775,270,964	771,665,575	768,394,658	765,562,023	763,182,972	761,275,019
RCNLD-SF :	1	2	3	4	5	6	7	8	9	10
1 RCNLD-SF BOY	$998,527,667	1,025,643,774	1,053,756,540	1,082,904,127	1,113,126,203	1,144,463,999	1,176,960,369	1,210,659,865	1,245,608,795	1,281,855,301
2 Capital Adds from NBV Case (Less PS)	27,116,107	28,112,766	29,147,588	30,222,076	31,337,795	32,496,371	33,699,496	34,948,930	36,246,505	37,594,127
3 RCNLD-SL EOY	1,025,643,774	1,053,756,540	1,082,904,127	1,113,126,203	1,144,463,999	1,176,960,369	1,210,659,865	1,245,608,795	1,281,855,301	1,319,449,428
4 Annual Depr NBV Case	15,434,363	15,919,753	16,916,245	17,943,824	19,010,086	20,116,525	20,985,177	21,796,330	22,640,321	23,516,845
5 SL Amortization of Diff (NBV v RCNLD) 20 yrs	34,164,982	34,164,982	34,164,982	34,164,982	34,164,982	34,164,982	34,164,982	34,164,982	34,164,982	34,164,982
6 Total Annual Depr & Amortization	49,599,345	50,084,735	51,081,227	52,108,806	53,175,068	54,281,507	55,150,159	55,961,312	56,805,303	57,681,827
7 Cummulative Depr & Amortization	49,599,345	99,684,079	150,765,306	202,874,113	256,049,181	310,330,688	365,480,847	421,442,160	478,247,463	535,929,290
8 Net Book Value	976,044,429	954,072,460	932,138,821	910,252,091	888,414,818	866,629,681	845,179,018	824,166,636	803,607,838	783,520,138
Income Method :										
1 Income Value BOY	$503,069,142	$530,185,249	$558,298,015	$587,445,602	$617,667,678	$649,005,474	$681,501,844	$715,201,340	$750,150,270	$786,396,776
2 Capital Adds from NBV Case (Less PS)	27,116,107	28,112,766	29,147,588	30,222,076	31,337,795	32,496,371	33,699,496	34,948,930	36,246,505	37,594,127
3 Income Value EOY	530,185,249	558,298,015	587,445,602	617,667,678	649,005,474	681,501,844	715,201,340	750,150,270	786,396,776	823,990,903
4 Annual Depr NBV Case	15,434,363	15,919,753	16,916,245	17,943,824	19,010,086	20,116,525	20,985,177	21,796,330	22,640,321	23,516,845
5 SL Amortization of Diff (NBV v Income) 20 yrs	9,392,056	9,392,056	9,392,056	9,392,056	9,392,056	9,392,056	9,392,056	9,392,056	9,392,056	9,392,056
6 Total Annual Depr & Amortization	24,826,418	25,311,808	26,308,301	27,335,880	28,402,142	29,508,581	30,377,233	31,188,386	32,032,377	32,908,901
7 Cummulative Depr & Amortization	24,826,418	50,138,227	76,446,528	103,782,408	132,184,550	161,693,131	192,070,364	223,258,750	255,291,127	288,200,027
8 Net Book Value	505,358,831	508,159,788	510,999,074	513,885,271	516,820,924	519,808,714	523,130,977	526,891,521	531,105,649	535,790,875
RCNLD-PG&E SF :	1	2	3	4	5	6	7	8	9	10
1 RCNLD-SF BOY	$1,441,465,190	1,468,581,297	1,496,694,063	1,525,841,650	1,556,063,726	1,587,401,522	1,619,897,892	1,653,597,388	1,688,546,318	1,724,792,824
2 Capital Adds from NBV Case (Less PS)	27,116,107	28,112,766	29,147,588	30,222,076	31,337,795	32,496,371	33,699,496	34,948,930	36,246,505	37,594,127
3 RCNLD-SL EOY	1,468,581,297	1,496,694,063	1,525,841,650	1,556,063,726	1,587,401,522	1,619,897,892	1,653,597,388	1,688,546,318	1,724,792,824	1,762,386,951
4 Annual Depr NBV Case	15,434,363	15,919,753	16,916,245	17,943,824	19,010,086	20,116,525	20,985,177	21,796,330	22,640,321	23,516,845
5 SL Amortization of Diff (NBV v RCNLD) 20 yrs	56,311,873	56,311,873	56,311,873	56,311,873	56,311,873	56,311,873	56,311,873	56,311,873	56,311,873	56,311,873
6 Total Annual Depr & Amortization	71,746,236	72,231,626	73,228,118	74,255,697	75,321,959	76,428,398	77,297,050	78,108,203	78,952,194	79,828,718
7 Cummulative Depr & Amortization	71,746,236	143,977,862	217,205,980	291,461,677	366,783,637	443,212,035	520,509,085	598,617,289	677,569,483	757,398,201
8 Net Book Value	1,396,835,061	1,352,716,201	1,308,635,670	1,264,602,049	1,220,617,885	1,176,685,857	1,133,088,303	1,089,929,029	1,047,223,341	1,004,988,749

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Workpaper

Investment in Assets All Cases

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
NBV Case										
1 Original Cost	$993,824,833	$1,032,812,776	$1,073,251,201	$1,115,194,013	$1,158,697,113	$1,203,818,482	$1,250,618,251	$1,299,158,787	$1,349,504,768	$1,401,723,278
2 Capital Additions	38,987,942	40,438,426	41,942,811	43,503,100	45,121,369	46,799,769	48,540,535	50,345,981	52,218,510	54,160,612
3 Total Original Cost	1,032,812,776	1,073,251,201	1,115,194,013	1,158,697,113	1,203,818,482	1,250,618,251	1,299,158,787	1,349,504,768	1,401,723,278	1,455,883,890
4 Annual Depr	24,539,067	25,605,723	26,718,744	27,880,146	29,092,030	30,356,593	31,676,123	33,053,010	34,489,747	35,988,936
5 Cumulative Depr	571,475,907	597,081,630	623,800,374	651,680,520	680,772,550	711,129,143	742,805,266	775,858,276	810,348,023	846,336,959
6 Net Book Value	461,336,869	476,169,571	491,393,639	507,016,593	523,045,932	539,489,108	556,353,520	573,646,492	591,375,255	609,546,931
PG&E Avg System Alloc to CCSF										
PG&E Avg System NBV Alloc to CCSF	640,992,239	625,376,092	640,098,566	655,167,634	670,591,454	686,378,379	702,536,956	719,075,936	736,004,272	753,331,132
PG&E Annual Depr Allocated to CCSF	34,262,442	35,183,277	36,128,860	37,099,856	38,096,949	39,120,840	40,172,249	41,251,916	42,360,599	43,499,080
RCNLD-SL :	11	12	13	14	15	16	17	18	19	20
1 RCNLD-SL BOY	1,115,406,840	1,154,394,782	1,194,833,208	1,236,776,019	1,280,279,120	1,325,400,488	1,372,200,258	1,420,740,793	1,471,086,774	1,523,305,285
2 Capital Adds from NBV Case (Less PS)	38,987,942	40,438,426	41,942,811	43,503,100	45,121,369	46,799,769	48,540,535	50,345,981	52,218,510	54,160,612
3 RCNLD-SL EOY	1,154,394,782	1,194,833,208	1,236,776,019	1,280,279,120	1,325,400,488	1,372,200,258	1,420,740,793	1,471,086,774	1,523,305,285	1,577,465,896
4 Annual Depr NBV Case	24,539,067	25,605,723	26,718,744	27,880,146	29,092,030	30,356,593	31,676,123	33,053,010	34,489,747	35,988,936
5 SL Amortization of Diff (NBV v RCNLD) 20 yrs	23,977,852	23,977,852	23,977,852	23,977,852	23,977,852	23,977,852	23,977,852	23,977,852	23,977,852	23,977,852
6 Total Annual Depr & Amortization	48,516,920	49,583,576	50,696,597	51,857,998	53,069,883	54,334,445	55,653,975	57,030,862	58,467,600	59,966,788
7 Cumulative Depr & Amortization	482,574,916	532,158,492	582,855,088	634,713,086	687,782,969	742,117,415	797,771,390	854,802,253	913,269,852	973,236,640
8 Net Book Value	671,819,866	662,674,716	653,920,931	645,566,033	637,617,519	630,082,843	622,969,403	616,284,522	610,035,432	604,229,256
What if 30 Amortization - NBV										
RCNLD-SF :	11	12	13	14	15	16	17	18	19	20
1 RCNLD-SF BOY	1,319,449,428	1,358,437,370	1,398,875,796	1,440,818,607	1,484,321,708	1,529,443,076	1,576,242,846	1,624,783,381	1,675,129,362	1,727,347,873
2 Capital Adds from NBV Case (Less PS)	38,987,942	40,438,426	41,942,811	43,503,100	45,121,369	46,799,769	48,540,535	50,345,981	52,218,510	54,160,612
3 RCNLD-SL EOY	1,358,437,370	1,398,875,796	1,440,818,607	1,484,321,708	1,529,443,076	1,576,242,846	1,624,783,381	1,675,129,362	1,727,347,873	1,781,508,484
4 Annual Depr NBV Case	24,539,067	25,605,723	26,718,744	27,880,146	29,092,030	30,356,593	31,676,123	33,053,010	34,489,747	35,988,936
5 SL Amortization of Diff (NBV v RCNLD) 20 yrs	34,164,982	34,164,982	34,164,982	34,164,982	34,164,982	34,164,982	34,164,982	34,164,982	34,164,982	34,164,982
6 Total Annual Depr & Amortization	58,704,049	59,770,705	60,883,726	62,045,127	63,257,012	64,521,575	65,841,105	67,217,992	68,654,729	70,153,918
7 Cumulative Depr & Amortization	594,633,339	654,404,044	715,287,771	777,332,898	840,589,910	905,111,485	970,952,590	1,038,170,582	1,106,825,311	1,176,979,228
8 Net Book Value	763,804,031	744,471,752	725,530,837	706,988,810	688,853,166	671,131,361	653,830,791	636,958,781	620,522,562	604,529,256
Income Method :										
1 Income Value BOY	$823,990,903	$862,978,845	$903,417,271	$945,360,082	$988,863,183	$1,033,984,551	$1,080,784,321	$1,129,324,856	$1,179,670,837	$1,231,889,348
2 Capital Adds from NBV Case (Less PS)	38,987,942	40,438,426	41,942,811	43,503,100	45,121,369	46,799,769	48,540,535	50,345,981	52,218,510	54,160,612
3 Income Value EOY	862,978,845	903,417,271	945,360,082	988,863,183	1,033,984,551	1,080,784,321	1,129,324,856	1,179,670,837	1,231,889,348	1,286,049,959
4 Annual Depr NBV Case	24,539,067	25,605,723	26,718,744	27,880,146	29,092,030	30,356,593	31,676,123	33,053,010	34,489,747	35,988,936
5 SL Amortization of Diff (NBV v. Income) 20 yrs	9,392,056	9,392,056	9,392,056	9,392,056	9,392,056	9,392,056	9,392,056	9,392,056	9,392,056	9,392,056
6 Total Annual Depr & Amortization	33,931,123	34,997,779	36,110,800	37,272,201	38,484,086	39,748,649	41,068,179	42,445,066	43,881,803	45,380,991
7 Cumulative Depr & Amortization	322,131,150	357,128,929	393,239,729	430,511,931	468,996,017	508,744,665	549,812,844	592,257,909	636,139,712	681,520,703
8 Net Book Value	540,847,695	546,288,342	552,120,353	558,351,252	564,988,535	572,039,656	579,512,012	587,412,928	595,749,636	604,529,256
RCNLD-PG&E SF :	11	12	13	14	15	16	17	18	19	20
1 RCNLD-SF BOY	1,762,386,951	1,801,374,893	1,841,813,319	1,883,756,130	1,927,259,231	1,972,380,599	2,019,180,369	2,067,720,904	2,118,066,885	2,170,285,396
2 Capital Adds from NBV Case (Less PS)	38,987,942	40,438,426	41,942,811	43,503,100	45,121,369	46,799,769	48,540,535	50,345,981	52,218,510	54,160,612
3 RCNLD-SL EOY	1,801,374,893	1,841,813,319	1,883,756,130	1,927,259,231	1,972,380,599	2,019,180,369	2,067,720,904	2,118,066,885	2,170,285,396	2,224,446,007
4 Annual Depr NBV Case	24,539,067	25,605,723	26,718,744	27,880,146	29,092,030	30,356,593	31,676,123	33,053,010	34,489,747	35,988,936
5 SL Amortization of Diff (NBV v RCNLD) 20 yrs	56,311,873	56,311,873	56,311,873	56,311,873	56,311,873	56,311,873	56,311,873	56,311,873	56,311,873	56,311,873
6 Total Annual Depr & Amortization	80,850,940	81,917,596	83,030,617	84,192,019	85,403,903	86,668,466	87,987,996	89,364,883	90,801,620	92,300,809
7 Cumulative Depr & Amortization	838,249,142	920,166,738	1,003,197,356	1,087,389,374	1,172,793,278	1,259,461,743	1,347,449,739	1,436,814,622	1,527,616,243	1,619,917,051
8 Net Book Value	963,125,751	921,646,581	880,558,775	839,869,857	799,587,322	759,718,625	720,271,165	681,252,263	642,669,153	604,528,956

Workpaper

Investment in Assets All Cases

	2022	2023	2024	2025	2026	2027	2027	2029	2030	2031
NBV Case										
1 Orginal Cost	$1,455,883,890	$1,512,058,759	$1,570,322,722	$1,630,753,391	$1,693,431,262	$1,758,439,818	$1,825,865,643	$1,895,798,534	$1,968,331,621	$2,043,561,494
2 Capital Additions	56,174,870	58,263,963	60,430,669	62,677,871	65,008,556	67,425,825	69,932,891	72,533,087	75,229,873	78,026,832
3 Total Original Cost	1,512,058,759	1,570,322,722	1,630,753,391	1,693,431,262	1,758,439,818	1,825,865,643	1,895,798,534	1,968,331,621	2,043,561,494	2,121,588,326
4 Annual Depr	37,553,291	39,185,644	40,888,953	42,666,300	44,520,904	46,456,124	48,475,463	50,582,578	52,781,284	55,075,563
5 Cummulative Depr	883,890,250	923,075,894	963,964,847	1,006,631,147	1,051,152,051	1,097,608,175	1,146,083,637	1,196,666,215	1,249,447,499	1,304,523,063
6 Net Book Value	628,168,510	647,246,828	666,788,544	686,800,116	707,287,768	728,257,469	749,714,896	771,665,406	794,113,994	817,065,263
PG&E Avg System Alloc to CCSF										
PG&E Avg System NBV Alloc to CCSF	771,065,897	789,218,171	807,797,781	826,814,789	846,279,491	866,202,427	886,594,385	907,466,406	928,829,792	950,696,141
PG&E Annual Depr Allocated to CCSF	44,668,158	45,868,656	47,101,419	48,367,313	49,667,230	51,002,083	52,372,811	53,780,379	55,225,776	56,710,020
RCNLD-SL :	21	22	23	24	25	26	27	28	29	30
1 RCNLD-SL BOY	1,577,465,896	1,633,640,766	1,691,904,728	1,752,335,398	1,815,013,269	1,880,021,825	1,947,447,650	2,017,380,540	2,089,913,628	2,165,143,500
2 Capital Adds from NBV Case (Less PS)	56,174,870	58,263,963	60,430,669	62,677,871	65,008,556	67,425,825	69,932,891	72,533,087	75,229,873	78,026,832
3 RCNLD-SL EOY	1,633,640,766	1,691,904,728	1,752,335,398	1,815,013,269	1,880,021,825	1,947,447,650	2,017,380,540	2,089,913,628	2,165,143,500	2,243,170,333
4 Annual Depr NBV Case	37,553,291	39,185,644	40,888,953	42,666,300	44,520,904	46,456,124	48,475,463	50,582,578	52,781,284	55,075,563
5 SL Amortization of Diff (NBV v RCNLD) 20 yrs										
6 Total Annual Depr & Amortization	37,553,291	39,185,644	40,888,953	42,666,300	44,520,904	46,456,124	48,475,463	50,582,578	52,781,284	55,075,563
7 Cummulative Depr & Amortization	1,010,789,931	1,049,975,575	1,090,864,528	1,133,530,828	1,178,051,732	1,224,507,856	1,272,983,319	1,323,565,896	1,376,347,181	1,431,422,744
8 Net Book Value	622,850,835	641,929,153	661,470,870	681,482,441	701,970,093	722,939,794	744,397,222	766,347,731	788,796,320	811,747,589
What if 30 Amortization - NBV										
RCNLD-SF :	21	22	23	24	25	26	27	28	29	30
1 RCNLD-SF BOY	1,781,508,484	1,837,683,354	1,895,947,316	1,956,377,986	2,019,055,857	2,084,064,413	2,151,490,238	2,221,423,128	2,293,956,216	2,369,186,088
2 Capital Adds from NBV Case (Less PS)	56,174,870	58,263,963	60,430,669	62,677,871	65,008,556	67,425,825	69,932,891	72,533,087	75,229,873	78,026,832
3 RCNLD-SL EOY	1,837,683,354	1,895,947,316	1,956,377,986	2,019,055,857	2,084,064,413	2,151,490,238	2,221,423,128	2,293,956,216	2,369,186,088	2,447,212,921
4 Annual Depr NBV Case	37,553,291	39,185,644	40,888,953	42,666,300	44,520,904	46,456,124	48,475,463	50,582,578	52,781,284	55,075,563
5 SL Amortization of Diff (NBV v RCNLD) 20 yrs										
6 Total Annual Depr & Amortization	37,553,291	39,185,644	40,888,953	42,666,300	44,520,904	46,456,124	48,475,463	50,582,578	52,781,284	55,075,563
7 Cummulative Depr & Amortization	1,214,532,519	1,253,718,163	1,294,607,116	1,337,273,416	1,381,794,320	1,428,250,444	1,476,725,907	1,527,308,484	1,580,089,769	1,635,165,332
8 Net Book Value	623,150,835	642,229,153	661,770,870	681,782,441	702,270,093	723,239,794	744,697,222	766,647,731	789,096,320	812,047,589
Income Method :										
1 Income Value BOY	$1,286,049,959	$1,342,224,829	$1,400,488,791	$1,460,919,461	$1,523,597,332	$1,588,605,888	$1,656,031,713	$1,725,964,603	$1,798,497,691	$1,873,727,563
2 Capital Adds from NBV Case (Less PS)	56,174,870	58,263,963	60,430,669	62,677,871	65,008,556	67,425,825	69,932,891	72,533,087	75,229,873	78,026,832
3 Income Value EOY	1,342,224,829	1,400,488,791	1,460,919,461	1,523,597,332	1,588,605,888	1,656,031,713	1,725,964,603	1,798,497,691	1,873,727,563	1,951,754,396
4 Annual Depr NBV Case	37,553,291	39,185,644	40,888,953	42,666,300	44,520,904	46,456,124	48,475,463	50,582,578	52,781,284	55,075,563
5 SL Amortization of Diff (NBV v. Income) 20 yrs										
6 Total Annual Depr & Amortization	37,553,291	39,185,644	40,888,953	42,666,300	44,520,904	46,456,124	48,475,463	50,582,578	52,781,284	55,075,563
7 Cummulative Depr & Amortization	719,073,994	758,259,638	799,148,591	841,814,891	886,335,795	932,791,919	981,267,382	1,031,849,959	1,084,631,244	1,139,706,807
8 Net Book Value	623,150,835	642,229,153	661,770,870	681,782,441	702,270,093	723,239,794	744,697,222	766,647,731	789,096,320	812,047,589
RCNLD-PG&E SF :	21	22	23	24	25	26	27	28	29	30
1 RCNLD-SF BOY	2,224,446,007	2,280,620,877	2,338,884,839	2,399,315,509	2,461,993,380	2,527,001,936	2,594,427,761	2,664,360,651	2,736,893,739	2,812,123,611
2 Capital Adds from NBV Case (Less PS)	56,174,870	58,263,963	60,430,669	62,677,871	65,008,556	67,425,825	69,932,891	72,533,087	75,229,873	78,026,832
3 RCNLD-SL EOY	2,280,620,877	2,338,884,839	2,399,315,509	2,461,993,380	2,527,001,936	2,594,427,761	2,664,360,651	2,736,893,739	2,812,123,611	2,890,150,444
4 Annual Depr NBV Case	37,553,291	39,185,644	40,888,953	42,666,300	44,520,904	46,456,124	48,475,463	50,582,578	52,781,284	55,075,563
5 SL Amortization of Diff (NBV v RCNLD) 20 yrs										
6 Total Annual Depr & Amortization	37,553,291	39,185,644	40,888,953	42,666,300	44,520,904	46,456,124	48,475,463	50,582,578	52,781,284	55,075,563
7 Cummulative Depr & Amortization	1,657,470,342	1,696,655,986	1,737,544,939	1,780,211,239	1,824,732,143	1,871,188,267	1,919,663,730	1,970,246,307	2,023,027,592	2,078,103,155
8 Net Book Value	623,150,535	642,228,853	661,770,570	681,782,141	702,269,793	723,239,494	744,696,922	766,647,431	789,096,020	812,047,289

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CALCUALTION OF NET BOOK VALUE AS OF YEAR END 1996-2001-2011

Post 1996 Cost Inc Rate 2.50%
Prior 1996 Cost Inc Rate 3.50%

Transmission Plant

Station Equipment	Inputs	1981 Service Life 28	1982 Depr Rate 3.57%	1982 Escalation 3.50%	1981 Avg Age 8	1982 1981 Avg Remain Life 20	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997 Escalation 2.50%
1 Original Cost 1981 Capital Adds	2,311,016	85,536	88,690	91,976	95,376	98,892	102,559	106,249	110,200	114,356	118,583	122,966	127,512	132,225	137,113	142,181	146,912
2 Cumulative Investment	Age 1981	2,399,552	2,488,250	2,580,226	2,675,602	2,774,504	2,877,062	2,983,410	3,093,690	3,208,046	3,326,629	3,449,595	3,577,107	3,709,332	3,846,445	3,988,626	4,134,638
3 Depreciation of OC and Capital Additions																		
1981			82,643	82,643	82,643	82,643	82,643	82,643	82,643	82,643	82,643	82,643	82,643	82,643	82,643	82,643	82,643	82,643
1982			3,055	3,055	3,055	3,055	3,055	3,055	3,055	3,055	3,055	3,055	3,055	3,055	3,055	3,055	3,055	3,055
1983			3,168	3,168	3,168	3,168	3,168	3,168	3,168	3,168	3,168	3,168	3,168	3,168	3,168	3,168	3,168	3,168
1984				3,285	3,285	3,285	3,285	3,285	3,285	3,285	3,285	3,285	3,285	3,285	3,285	3,285	3,285	3,285
1985					3,406	3,406	3,406	3,406	3,406	3,406	3,406	3,406	3,406	3,406	3,406	3,406	3,406	3,406
1986						3,532	3,532	3,532	3,532	3,532	3,532	3,532	3,532	3,532	3,532	3,532	3,532	3,532
1987							3,663	3,663	3,663	3,663	3,663	3,663	3,663	3,663	3,663	3,663	3,663	3,663
1988								3,798	3,798	3,798	3,798	3,798	3,798	3,798	3,798	3,798	3,798	3,798
1989									3,939	3,939	3,939	3,939	3,939	3,939	3,939	3,939	3,939	3,939
1990										4,084	4,084	4,084	4,084	4,084	4,084	4,084	4,084	4,084
1991											4,235	4,235	4,235	4,235	4,235	4,235	4,235	4,235
1992												4,392	4,392	4,392	4,392	4,392	4,392	4,392
1993													4,554	4,554	4,554	4,554	4,554	4,554
1994														4,722	4,722	4,722	4,722	4,722
1995															4,897	4,897	4,897	4,897
1996																5,078	5,078	5,078
1997																		5,215
1998																		
1999																		
2000																		
2001																		
2002																		
2003																		
2004																		
2005																		
2006																		
2007																		
2008																		
2009																		
2010																		
2011																		
Annual Depr	661.147	0	85,698	88,966	92,151	95,557	99,089	102,752	106,550	110,488	114,573	118,808	123,199	127,753	132,476	137,373	142,451	147,665
Cumm Depr		661,147	746,845	835,810	927,961	1,023,518	1,122,607	1,225,359	1,331,808	1,442,297	1,556,870	1,675,677	1,798,877	1,926,630	2,059,106	2,196,478	2,338,929	2,486,594
Net Book Value		1,652,869	1,652,707	1,652,539	1,652,365	1,652,184	1,651,997	1,651,803	1,651,602	1,651,393	1,651,176	1,650,951	1,650,719	1,650,477	1,650,226	1,649,967	1,649,697	1,648,044
CA Depr		0	3,055	6,223	9,508	12,914	16,446	20,109	23,907	27,845	31,930	36,165	40,556	45,110	49,833	54,730	59,808	65,022
Cumm CA Depr		0	3,055	9,277	18,786	31,700	48,146	68,255	92,162	120,007	151,937	188,102	228,658	273,768	323,601	378,331	438,139	503,161

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Post 1996	Cost Esc Rate	2.50%									
Prior 1996	Cost Esc Rate	3.50%									
	Transmission Plant		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Investment Adjustment												
		Input										
1 Original Cost (Bal) / Capital Adds			151.337	156.370	162.642	168.595	174.767	181.165	187.797	194.672	201.798	209.185
2 Cumulative Investment			4.285.596	4.442.894	4.605.533	4.774.131	4.948.898	5.130.063	5.317.860	5.312.532	5.714.330	5.923.515
3 Depreciation of OC and Capital Additions												
	1981		82.643	82.643	82.643	82.643						
	1982		3.053	3.053	3.053	3.053	3.055	3.055	3.055	3.055	3.055	3.053
	1983		3.168	3.168	3.168	3.168	3.168	3.168	3.168	3.168	3.168	3.168
	1984		3.285	3.285	3.285	3.285	3.285	3.285	3.285	3.285	3.285	3.285
	1985		3.406	3.406	3.406	3.406	3.406	3.406	3.406	3.406	3.406	3.406
	1986		3.532	3.532	3.532	3.532	3.532	3.532	3.532	3.532	3.532	3.532
	1987		3.663	3.663	3.663	3.663	3.663	3.663	3.663	3.663	3.663	3.663
	1988		3.798	3.798	3.798	3.798	3.798	3.798	3.798	3.798	3.798	3.798
	1989		3.939	3.939	3.939	3.939	3.939	3.939	3.939	3.939	3.939	3.939
	1990		4.084	4.084	4.084	4.084	4.084	4.084	4.084	4.084	4.084	4.084
	1991		4.233	4.233	4.233	4.233	4.233	4.233	4.233	4.233	4.233	4.233
	1992		4.392	4.392	4.392	4.392	4.392	4.392	4.392	4.392	4.392	4.392
	1993		4.554	4.554	4.554	4.554	4.554	4.554	4.554	4.554	4.554	4.554
	1994		4.722	4.722	4.722	4.722	4.722	4.722	4.722	4.722	4.722	4.722
	1995		4.897	4.897	4.897	4.897	4.897	4.897	4.897	4.897	4.897	4.897
	1996		5.078	5.078	5.078	5.078	5.078	5.078	5.078	5.078	5.078	5.078
	1997		5.213	5.213	5.213	5.213	5.213	5.213	5.213	5.213	5.213	5.213
	1998		3.406	5.406	5.406	5.406	5.406	5.406	5.406	5.406	5.406	5.406
	1999			5.604	5.604	5.604	5.604	5.604	5.604	5.604	5.604	5.604
	2000				5.809	5.809	5.809	5.809	5.809	5.809	5.809	5.809
	2001					6.021	6.021	6.021	6.021	6.021	6.021	6.021
	2002						6.242	6.242	6.242	6.242	6.242	6.242
	2003							6.470	6.470	6.470	6.470	6.470
	2004								6.707	6.707	6.707	6.707
	2005									6.953	6.953	6.953
	2006										7.207	7.207
	2007											7.471
	2008											
	2009											
	2010											
	2011											
	Annual Depr	[661.847]	153.074	158.674	164.482	170.501	94.103	100.373	107.280	114.233	121.440	128.911
	Cmtm Depr		2.639.665	2.798.339	2.962.822	3.133.327	3.227.430	3.326.003	3.433.283	3.549.316	3.670.933	3.799.666
Net Book Value			1.646.331	1.644.554	1.642.713	1.640.804	1.721.469	1.802.061	1.882.577	1.963.016	2.043.373	2.123.649
	CA Depr		70.428	76.031	81.810	87.954	91.103	100.373	107.280	114.233	121.440	128.911
	Cum CA Depr		113.450	116.459	137.671	169.701	181.964	191.676	207.853	221.513	235.072	250.350

Post 1996	Cost Esc Rate	2.50%				
Prior 1996	Cost Esc Rate	3.50%				
	Transmission Plant	2000	2002	2010	2013	Cumulative
Mobile Equipment						
	figures					
1 Original Cost 1981 Capital Add.		210.843	224.781	233.010	241.539	6.839.688
2 Cumulative Investment		6.140.376	6.365.139	6.598.149	6.839.688	
3 Depreciation of OC and Capital Additions						
	1981					
	1982	3.053	3.053			
	1983	3.168	3.168	3.168		
	1984	3.285	3.285	3.285	3.285	
	1985	3.406	3.406	3.406	3.406	
	1986	3.532	3.532	3.532	3.532	
	1987	3.663	3.663	3.663	3.663	
	1988	3.798	3.798	3.798	3.798	
	1989	3.939	3.939	3.939	3.939	
	1990	4.084	4.084	4.084	4.084	
	1991	4.235	4.235	4.235	4.235	
	1992	4.392	4.392	4.392	4.392	
	1993	4.554	4.554	4.554	4.554	
	1994	4.722	4.722	4.722	4.722	
	1995	4.897	4.897	4.897	4.897	
	1996	5.078	5.078	5.078	5.078	
	1997	5.215	5.215	5.215	5.215	
	1998	5.406	5.406	5.406	5.406	
	1999	5.604	5.604	5.604	5.604	
	2000	5.809	5.809	5.809	5.809	
	2001	6.021	6.021	6.021	6.021	
	2002	6.242	6.242	6.242	6.242	
	2003	6.470	6.470	6.470	6.470	
	2004	6.707	6.707	6.707	6.707	
	2005	6.953	6.953	6.953	6.953	
	2006	7.207	7.207	7.207	7.207	
	2007	7.471	7.471	7.471	7.471	
	2008	7.744	7.744	7.744	7.744	
	2009		8.026	8.026	8.026	
	2010			8.322	8.322	
	2011				8.626	
	Annual Depr 661.143	136.655	144.683	149.950	155.409	4.306.562
	Cumm Depr	3.930.321	4.081.204	4.231.154	4.386.562	
Net Book Value		2.203.837	2.283.935	2.366.995	2.453.126	2.453.126
	CA Depr	136.655	144.683	149.950	155.409	
	Cum CA Depr	265.566	281.388	294.633	305.358	

CALCUALTION OF NET BOOK VALUE AS OF YEAR END 1996-2001-2011

Transmission Plant																	
Underground Conduit	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
	Service Life	Depr Rate	Escalation	Avg Age	1981 Avg Remain. Life												Escalation
Inputs	60	1.67%	3.50%	11	49												3.50%
1 Original Cost 1981 Capital Additions	13,418,819	221,820	235,819	239,886	244,024	248,234	252,516	256,872	261,303	265,810	270,396	275,060	279,805	284,631	289,541	294,536	299,721
2 Cumulative Investment		13,640,639	13,900,457	14,166,344	14,390,368	14,638,602	14,891,118	15,147,989	15,409,292	15,675,103	15,945,498	16,220,558	16,500,363	16,784,994	17,074,535	17,369,071	17,668,792
3 Depreciation of OC and Capital Additions																	
1981		223,980	223,980	223,980	223,980	223,980	223,980	223,980	223,980	223,980	223,980	223,980	223,980	223,980	223,980	223,980	223,980
1982		3,864	3,864	3,864	3,864	3,864	3,864	3,864	3,864	3,864	3,864	3,864	3,864	3,864	3,864	3,864	3,864
1983			3,930	3,930	3,930	3,930	3,930	3,930	3,930	3,930	3,930	3,930	3,930	3,930	3,930	3,930	3,930
1984				3,998	3,998	3,998	3,998	3,998	3,998	3,998	3,998	3,998	3,998	3,998	3,998	3,998	3,998
1985					4,067	4,067	4,067	4,067	4,067	4,067	4,067	4,067	4,067	4,067	4,067	4,067	4,067
1986						4,137	4,137	4,137	4,137	4,137	4,137	4,137	4,137	4,137	4,137	4,137	4,137
1987							4,209	4,209	4,209	4,209	4,209	4,209	4,209	4,209	4,209	4,209	4,209
1988								4,281	4,281	4,281	4,281	4,281	4,281	4,281	4,281	4,281	4,281
1989									4,355	4,355	4,355	4,355	4,355	4,355	4,355	4,355	4,355
1990										4,430	4,430	4,430	4,430	4,430	4,430	4,430	4,430
1991											4,507	4,507	4,507	4,507	4,507	4,507	4,507
1992												4,584	4,584	4,584	4,584	4,584	4,584
1993													4,663	4,663	4,663	4,663	4,663
1994														4,744	4,744	4,744	4,744
1995															4,826	4,826	4,826
1996																4,909	4,909
1997																	4,945
1998																	
1999																	
2000																	
2001																	
2002																	
2003																	
2004																	
2005																	
2006																	
2007																	
2008																	
2009																	
2010																	
2011																	
Annual Depr [2,463,783]	0	227,844	231,774	235,772	239,839	243,977	248,185	252,466	256,822	261,252	265,756	270,343	275,006	279,750	284,576	289,485	294,930
Cumm Depr	2,463,783	2,691,627	2,923,401	3,159,174	3,399,013	3,642,990	3,891,175	4,143,642	4,400,463	4,661,715	4,927,470	5,197,813	5,472,822	5,752,572	6,037,147	6,326,632	6,621,562
Net Book Value	10,975,036	10,979,012	10,983,056	10,987,170	10,991,355	10,995,612	10,999,943	11,004,348	11,008,829	11,013,388	11,018,025	11,022,742	11,027,541	11,032,422	11,037,386	11,042,439	11,044,731
CA Depr	0	3,864	7,794	11,792	15,859	19,996	24,205	28,486	32,841	37,271	41,776	46,362	51,026	55,770	60,595	65,504	70,450
Cum CA Depr	0	3,864	11,658	19,586	27,651	35,856	44,201	52,691	61,327	70,113	79,049	88,140	97,388	106,795	116,363	126,099	135,954

Transmission Plant

Undepreciated Capital

Inputs

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
1 Original Cost 1981 Capital Additions	301.791	306.946	312.190	317.523	322.947	328.464	334.076	339.783	345.588	351.491
2 Cumulative Investment	17.967.583	18.274.529	18.586.719	18.904.242	19.227.190	19.555.654	19.889.730	20.229.513	20.575.100	20.926.592
3 Depreciation of OC and Capital Additions										
1981	223.960	223.960	223.960	223.960	223.960	223.960	223.960	223.960	223.960	223.960
1982	3.864	3.864	3.864	3.864	3.864	3.864	3.864	3.864	3.864	3.864
1983	3.930	3.930	3.930	3.930	3.930	3.930	3.930	3.930	3.930	3.930
1984	3.998	3.998	3.998	3.998	3.998	3.998	3.998	3.998	3.998	3.998
1985	4.067	4.067	4.067	4.067	4.067	4.067	4.067	4.067	4.067	4.067
1986	4.137	4.137	4.137	4.137	4.137	4.137	4.137	4.137	4.137	4.137
1987	4.209	4.209	4.209	4.209	4.209	4.209	4.209	4.209	4.209	4.209
1988	4.281	4.281	4.281	4.281	4.281	4.281	4.281	4.281	4.281	4.281
1989	4.355	4.355	4.355	4.355	4.355	4.355	4.355	4.355	4.355	4.355
1990	4.430	4.430	4.430	4.430	4.430	4.430	4.430	4.430	4.430	4.430
1991	4.507	4.507	4.507	4.507	4.507	4.507	4.507	4.507	4.507	4.507
1992	4.584	4.584	4.584	4.584	4.584	4.584	4.584	4.584	4.584	4.584
1993	4.663	4.663	4.663	4.663	4.663	4.663	4.663	4.663	4.663	4.663
1994	4.744	4.744	4.744	4.744	4.744	4.744	4.744	4.744	4.744	4.744
1995	4.826	4.826	4.826	4.826	4.826	4.826	4.826	4.826	4.826	4.826
1996	4.909	4.909	4.909	4.909	4.909	4.909	4.909	4.909	4.909	4.909
1997	4.945	4.945	4.945	4.945	4.945	4.945	4.945	4.945	4.945	4.945
1998	5.030	5.030	5.030	5.030	5.030	5.030	5.030	5.030	5.030	5.030
1999		5.116	5.116	5.116	5.116	5.116	5.116	5.116	5.116	5.116
2000			5.203	5.203	5.203	5.203	5.203	5.203	5.203	5.203
2001				5.292	5.292	5.292	5.292	5.292	5.292	5.292
2002					5.382	5.382	5.382	5.382	5.382	5.382
2003						5.474	5.474	5.474	5.474	5.474
2004							5.568	5.568	5.568	5.568
2005								5.663	5.663	5.663
2006									5.760	5.760
2007										5.858
2008										
2009										
2010										
2011										
Annual Dept [2.161.783]	299.160	304.575	309.779	315.073	320.453	325.920	331.495	337.159	342.918	348.777
Cumm Dept	6.929.521	7.225.097	7.534.876	7.849.946	8.170.399	8.496.327	8.827.822	9.164.981	9.507.899	9.856.676
Net Book Value	11.037.062	11.049.432	11.051.843	11.054.296	11.056.790	11.059.327	11.061.907	11.064.532	11.067.201	11.069.916
CA Dept	75.479	80.595	85.798	91.090	96.472	101.947	107.515	113.178	118.938	124.796
Cum CA Dept	145.929	156.075	166.394	176.889	187.563	198.420	209.462	220.693	232.116	243.734

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Transmission Plant

Underground Conduit	2008	2009	2010	2011	Cumulative
1 Original Cost (Plus) Capital Additions	157.496	363.603	369.815	376.832	22 393.638
2 Cumulative Investment	21 288.087	21.647.691	22 017.505	22 393.638	
3 Depreciation of Old and Capital Additions					
1981	223.960	223.960	223.960	223.960	
1982	3.864	3.864	3.864	3.864	
1983	3.930	3.930	3.930	3.930	
1984	3.998	3.998	3.998	3.998	
1985	4.067	4.067	4.067	4.067	
1986	4.137	4.137	4.137	4.137	
1987	4.209	4.209	4.209	4.209	
1988	4.281	4.281	4.281	4.281	
1989	4.355	4.355	4.355	4.355	
1990	4.430	4.430	4.430	4.430	
1991	4.507	4.507	4.507	4.507	
1992	4.584	4.584	4.584	4.584	
1993	4.663	4.663	4.663	4.663	
1994	4.744	4.744	4.744	4.744	
1995	4.826	4.826	4.826	4.826	
1996	4.909	4.909	4.909	4.909	
1997	4.915	4.915	4.915	4.915	
1998	5.030	5.030	5.030	5.030	
1999	5.116	5.116	5.116	5.116	
2000	5.203	5.203	5.203	5.203	
2001	5.292	5.292	5.292	5.292	
2002	5.382	5.382	5.382	5.382	
2003	5.474	5.474	5.474	5.474	
2004	5.568	5.568	5.568	5.568	
2005	5.663	5.663	5.663	5.663	
2006	5.760	5.760	5.760	5.760	
2007	5.858	5.858	5.858	5.858	
2008	5.958	5.958	5.958	5.958	
2009		6.060	6.060	6.060	
2010			6.164	6.164	
2011				6.269	
Annual Depr	[2.463.764]	351.745	360.795	366.930	373 227	11.312.391
Cumm Depr		10.211.411	10.572.206	10.939.164	11.312.391	
Net Book Value		11.072 677	11.075.483	11.078 341	11.081.246	11.081.246
CA Depr		130.754	136.885	142.978	149 247	
Cumt CA Depr		255.551	267.569	239.793	292.225	

CALCUALTION OF NET BOOK VALUE AS OF YEAR END 1996-2001 2011

Transmission Plant

Underground Conductors and Devices		1981 Service Life	1982 Depr Rate	1983 Escalation	1984 Avg Age	1985 1981 Avg Remain. Life	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997 Escalation
	Inputs	32	3.13%	3.50%	11	21												2.50%
1 Original Cost 1981 Capital Adds.		7,611,752	246,193	254,355	262,376	270,862	279,823	288,667	298,003	307,642	317,592	327,864	338,469	349,416	360,717	372,384	384,429	393,028
2 Cumulative Investment			7,857,945	8,112,300	8,374,676	8,645,538	8,925,360	9,213,627	9,511,630	9,819,272	10,136,864	10,464,728	10,803,197	11,152,613	11,513,330	11,885,714	12,270,143	12,663,171
3 Depreciation of Original Capital Additions																		
	1981		237,867	237,867	237,867	237,867	237,867	237,867	237,867	237,867	237,867	237,867	237,867	237,867	237,867	237,867	237,867	237,867
	1982		7,694	7,694	7,694	7,694	7,694	7,694	7,694	7,694	7,694	7,694	7,694	7,694	7,694	7,694	7,694	7,694
	1983			7,942	7,942	7,942	7,942	7,942	7,942	7,942	7,942	7,942	7,942	7,942	7,942	7,942	7,942	7,942
	1984				8,199	8,199	8,199	8,199	8,199	8,199	8,199	8,199	8,199	8,199	8,199	8,199	8,199	8,199
	1985					8,464	8,464	8,464	8,464	8,464	8,464	8,464	8,464	8,464	8,464	8,464	8,464	8,464
	1986						8,738	8,738	8,738	8,738	8,738	8,738	8,738	8,738	8,738	8,738	8,738	8,738
	1987							9,021	9,021	9,021	9,021	9,021	9,021	9,021	9,021	9,021	9,021	9,021
	1988								9,313	9,313	9,313	9,313	9,313	9,313	9,313	9,313	9,313	9,313
	1989									9,614	9,614	9,614	9,614	9,614	9,614	9,614	9,614	9,614
	1990										9,925	9,925	9,925	9,925	9,925	9,925	9,925	9,925
	1991											10,246	10,246	10,246	10,246	10,246	10,246	10,246
	1992												10,577	10,577	10,577	10,577	10,577	10,577
	1993													10,919	10,919	10,919	10,919	10,919
	1994														11,272	11,272	11,272	11,272
	1995															11,637	11,637	11,637
	1996																12,013	12,013
	1997																	12,202
	1998																	
	1999																	
	2000																	
	2001																	
	2002																	
	2003																	
	2004																	
	2005																	
	2006																	
	2007																	
	2008																	
	2009																	
	2010																	
	2011																	
Annual Depr	(2,616,540)	0	245,561	253,503	261,702	270,167	278,905	287,926	297,238	306,852	316,777	327,023	337,600	348,519	359,792	371,429	383,442	395,724
Cumm Depr		2,616,540	2,862,101	3,115,604	3,377,306	3,647,473	3,926,378	4,214,304	4,511,542	4,818,395	5,135,172	5,462,194	5,799,794	6,148,313	6,508,105	6,879,534	7,262,976	7,658,700
Net Book Value		4,995,212	4,995,844	4,996,496	4,997,069	4,997,865	4,998,582	4,999,323	5,000,088	5,000,877	5,001,693	5,002,534	5,003,403	5,004,299	5,005,225	5,006,181	5,007,167	5,004,971
CA Depr		0	7,694	15,636	23,835	32,300	41,038	50,059	59,371	68,985	78,910	89,156	99,733	110,652	121,924	133,561	145,575	157,857
Cumm CA Depr		0	7,694	23,329	39,471	56,135	73,337	91,096	109,430	128,356	147,895	168,065	189,888	210,385	232,576	255,486	279,136	303,432

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Transmission Plant

Underground Conductors and Devices

		1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
1 Unitized Cost (1998 Capital Adds		405.617	418.610	432.048	445.956	460.338	474.876	490.087	505.785	521.986	539.706
2 Cumulative Investment		13 068.786	13.197.398	13 919.416	14.365.272	14.825.610	15.300.486	15.790.574	16 296 359	16.818.345	17.358.052
3 Depreciation of O&M Capital Additions											
	1981										
	1982	237.867	237.867	237.867	237.867	237.867					
	1983	7.691	7.691	7.691	7.691	7.691	7.691	7.691	7.691	7.691	7.691
	1984	7.942	7.942	7.942	7.942	7.942	7.942	7.942	7.942	7.942	7.942
	1985	8.199	8.199	8.199	8.199	8.199	8.199	8.199	8.199	8.199	8.199
	1986	8.464	8.464	8.464	8.464	8.464	8.464	8.464	8.464	8.464	8.464
	1987	8.738	8.738	8.738	8.738	8.738	8.738	8.738	8.738	8.738	8.738
	1988	9.021	9.021	9.021	9.021	9.021	9.021	9.021	9.021	9.021	9.021
	1989	9.313	9.313	9.313	9.313	9.313	9.313	9.313	9.313	9.313	9.313
	1990	9.614	9.614	9.614	9.614	9.614	9.614	9.614	9.614	9.614	9.614
	1991	9.925	9.925	9.925	9.925	9.925	9.925	9.925	9.925	9.925	9.925
	1992	10.246	10.246	10.246	10.246	10.246	10.246	10.246	10.246	10.246	10.246
	1993	10.577	10.577	10.577	10.577	10.577	10.577	10.577	10.577	10.577	10.577
	1994	10.919	10.919	10.919	10.919	10.919	10.919	10.919	10.919	10.919	10.919
	1995	11.272	11.272	11.272	11.272	11.272	11.272	11.272	11.272	11.272	11.272
	1996	11.637	11.637	11.637	11.637	11.637	11.637	11.637	11.637	11.637	11.637
	1997	12.013	12.013	12.013	12.013	12.013	12.013	12.013	12.013	12.013	12.013
	1998	12.282	12.282	12.282	12.282	12.282	12.282	12.282	12.282	12.282	12.282
	1999	12.676	12.676	12.676	12.676	12.676	12.676	12.676	12.676	12.676	12.676
	2000		13.082	13.082	13.082	13.082	13.082	13.082	13.082	13.082	13.082
	2001			13.501	13.501	13.501	13.501	13.501	13.501	13.501	13.501
	2002				13.933	13.933	13.933	13.933	13.933	13.933	13.933
	2003					14.379	14.379	14.379	14.379	14.379	14.379
	2004						14.840	14.840	14.840	14.840	14.840
	2005							15.315	15.315	15.315	15.315
	2006								15.806	15.806	15.806
	2007									16.312	16.312
	2008										16.833
	2009										
	2010										
	2011										
Annual Depr [2.616 510]		408.400	421.481	434.982	448.915	463.294	240.267	255.582	271.388	287.700	304.534
Cumm Depr		8.067.699	8.488.580	8.923.562	9.372.477	9.835.771	10.076.038	10.331.620	10.603.007	10.890.707	11.195.242
Net Book Value		5.001.689	4.709.817	4.995.854	4.992.795	4.989.839	5.224.448	5.458.954	5.693.352	5.927.638	6.161.610
CY Depr		170.532	183.614	197.114	211.048	225.427	240.267	255.582	271.388	287.700	304.534
Cum CA Depr		329.389	354.146	380.728	409.162	436.474	465.694	495.849	526.970	559.088	592.234

Transmission Plant

		2008	2009	2010	2011	Cumulative
Underground Conductors and Devices						
	Depr.					
1 Unitized Cost EMF/C apital Adds		353.962	373.770	392.148	641.116	19.689.817
2 Cumulative Investment		17.912.433	18 486.203	19 078.731	19 689 817	
3 Depreciation of OC and Capital Additions						
	1981					
	1982	7.694	7.694	7.694	7.694	
	1983	7.942	7.942	7.942	7.942	
	1984	8.199	8.199	8.199	8.199	
	1985	8.464	8.464	8.464	8.464	
	1986	8.738	8.738	8.738	8.738	
	1987	9.021	9.021	9.021	9.021	
	1988	9.313	9.313	9.313	9.313	
	1989	9.614	9.614	9.614	9.614	
	1990	9.925	9.925	9.925	9.925	
	1991	10.246	10.246	10.246	10.246	
	1992	10.577	10.577	10.577	10.577	
	1993	10.919	10.919	10.919	10.919	
	1994	11.272	11.272	11.272	11.272	
	1995	11.637	11.637	11.637	11.637	
	1996	12.013	12.013	12.013	12.013	
	1997	12.282	12.282	12.282	12.282	
	1998	12.676	12.676	12.676	12.676	
	1999	13.082	13.082	13.082	13.082	
	2000	13.501	13.501	13.501	13.501	
	2001	13.933	13.933	13.933	13.933	
	2002	14.379	14.379	14.379	14.379	
	2003	14.840	14.840	14.840	14.840	
	2004	15.315	15.315	15.315	15.315	
	2005	15.806	15.806	15.806	15.806	
	2006	16.312	16.312	16.312	16.312	
	2007	16.835	16.835	16.835	16.835	
	2008	17.374	17.374	17.374	17.374	
	2009		17.930	17.930	17.930	
	2010			18.505	18.505	
	2011				19.097	
	Annual Depr. 2.616.540	323.908	339.838	358.333	377.440	12.592.772
	Cumm Depr	11,317.150	11.656.988	12.015.321	12 592.772	
Net Book Value		6.595.664	6.629.595	6 963.400	7.097.075	7.097.075
	CA Depr	323.908	339.838	358.333	377.440	
	Cum CA Depr	626.443	661.787	698.182	735.784	

Workpapers

CALCULATION OF NET BOOK VALUE AS OF YEAR END 1996-2001-2011

Distribution Plant

Structures and Improvements		1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
		Service Life	Depr Rate	Escalation	Avg Age	1981 Avg Remain Life												Escalation
	Equals	50	2.00%	2.50%	15	35												2.50%
1 Original Cost 1981 Capital Adds		15 441 761	319 684	376 261	333 013	329 908	316 944	354 326	361 436	368 926	376 576	384 371	392 327	400 448	408 738	417 198	425 834	430 450
2 Cumulative Investment			15 761 405	16 087 667	16 420 681	16 760 589	17 107 534	17 461 859	17 822 116	18 192 054	18 568 630	18 953 001	19 345 328	19 745 776	20 154 513	20 571 712	20 997 546	21 427 996
3 Depreciation of OC and Capital Additions																		
	1981		308 835	308 835	308 835	308 835	308 835	308 835	308 835	308 835	308 835	308 835	308 835	308 835	308 835	308 835	308 835	308 835
	1982		6 393	6 393	6 393	6 393	6 393	6 393	6 393	6 393	6 393	6 393	6 393	6 393	6 393	6 393	6 393	6 393
	1983			6 525	6 525	6 525	6 525	6 525	6 525	6 525	6 525	6 525	6 525	6 525	6 525	6 525	6 525	6 525
	1984				6 660	6 660	6 660	6 660	6 660	6 660	6 660	6 660	6 660	6 660	6 660	6 660	6 660	6 660
	1985					6 798	6 798	6 798	6 798	6 798	6 798	6 798	6 798	6 798	6 798	6 798	6 798	6 798
	1986						6 939	6 939	6 939	6 939	6 939	6 939	6 939	6 939	6 939	6 939	6 939	6 939
	1987							7 083	7 083	7 083	7 083	7 083	7 083	7 083	7 083	7 083	7 083	7 083
	1988								7 229	7 229	7 229	7 229	7 229	7 229	7 229	7 229	7 229	7 229
	1989									7 379	7 379	7 379	7 379	7 379	7 379	7 379	7 379	7 379
	1990										7 532	7 532	7 532	7 532	7 532	7 532	7 532	7 532
	1991											7 687	7 687	7 687	7 687	7 687	7 687	7 687
	1992												7 847	7 847	7 847	7 847	7 847	7 847
	1993													8 009	8 009	8 009	8 009	8 009
	1994														8 175	8 175	8 175	8 175
	1995															8 344	8 344	8 344
	1996																8 517	8 517
	1997																	8 695
	1998																	
	1999																	
	2000																	
	2001																	
	2002																	
	2003																	
	2004																	
	2005																	
	2006																	
	2007																	
	2008																	
	2009																	
	2010																	
	2011																	
	Annual Depr	4 632 528	0	315 228	321 753	328 414	335 212	342 151	349 233	356 462	363 841	371 373	379 060	386 907	394 916	403 090	411 434	419 951	428 360
	Cumm Depr		4 632 528	4 947 756	5 269 509	5 597 923	5 933 135	6 275 286	6 624 519	6 980 981	7 344 822	7 716 195	8 095 255	8 482 161	8 877 077	9 280 167	9 691 601	10 111 552	10 540 112
Net Book Value			10 809 233	10 813 619	10 818 157	10 822 758	10 827 454	10 832 248	10 837 141	10 842 135	10 847 232	10 852 433	10 857 746	10 863 166	10 868 699	10 874 346	10 880 111	10 885 994	10 887 884
	CA Depr		0	6 393	12 918	19 578	26 377	33 313	40 398	47 627	55 006	62 537	70 225	78 071	86 080	94 255	102 599	111 116	119 723
	Cum CA Depr		0	6 393	19 311	32 497	45 955	59 692	73 713	88 025	102 633	117 543	132 762	148 296	164 152	180 335	196 854	213 785	230 840

Distribution Plant

Structures and Improvements	Inputs	1998 Depr Rate 2.09%	1999	2000	2001	2002	2003	2004	2005	2006	2007
1 Original Cost 1981 Capital Adds		139.274	448.379	457.469	466.817	476.417	486.184	496.131	506.322	516.701	527.294
2 Cumulative Investment		21.867.270	22.315.349	22.773.010	23.239.963	23.716.282	24.202.466	24.698.646	25.204.938	25.721.639	26.248.933
3 Depreciation at OC and Capital Additions:											
1981		308.835	308.835	308.835	308.835	308.835					
1982		6.393	6.393	6.393	6.393	6.393	6.393	6.393	6.393	6.393	6.393
1983		6.525	6.525	6.525	6.525	6.525	6.525	6.525	6.525	6.525	6.525
1984		6.660	6.660	6.660	6.660	6.660	6.660	6.660	6.660	6.660	6.660
1985		6.798	6.798	6.798	6.798	6.798	6.798	6.798	6.798	6.798	6.798
1986		6.939	6.939	6.939	6.939	6.939	6.939	6.939	6.939	6.939	6.939
1987		7.083	7.083	7.083	7.083	7.083	7.083	7.083	7.083	7.083	7.083
1988		7.229	7.229	7.229	7.229	7.229	7.229	7.229	7.229	7.229	7.229
1989		7.379	7.379	7.379	7.379	7.379	7.379	7.379	7.379	7.379	7.379
1990		7.532	7.532	7.532	7.532	7.532	7.532	7.532	7.532	7.532	7.532
1991		7.687	7.687	7.687	7.687	7.687	7.687	7.687	7.687	7.687	7.687
1992		7.847	7.847	7.847	7.847	7.847	7.847	7.847	7.847	7.847	7.847
1993		8.009	8.009	8.009	8.009	8.009	8.009	8.009	8.009	8.009	8.009
1994		8.175	8.175	8.175	8.175	8.175	8.175	8.175	8.175	8.175	8.175
1995		8.344	8.344	8.344	8.344	8.344	8.344	8.344	8.344	8.344	8.344
1996		8.517	8.517	8.517	8.517	8.517	8.517	8.517	8.517	8.517	8.517
1997		8.609	8.609	8.609	8.609	8.609	8.609	8.609	8.609	8.609	8.609
1998		8.785	8.785	8.785	8.785	8.785	8.785	8.785	8.785	8.785	8.785
1999			8.966	8.966	8.966	8.966	8.966	8.966	8.966	8.966	8.966
2000				9.149	9.149	9.149	9.149	9.149	9.149	9.149	9.149
2001					9.337	9.337	9.337	9.337	9.337	9.337	9.337
2002						9.528	9.528	9.528	9.528	9.528	9.528
2003							9.724	9.724	9.724	9.724	9.724
2004								9.923	9.923	9.923	9.923
2005									10.126	10.126	10.126
2006										10.334	10.334
2007											10.546
2008											
2009											
2010											
2011											
Annual Depr	8,642,328	437.335	446.331	455.460	464.797	474.326	175.214	185.137	195.264	205.598	216.143
Cumm Depr		10.977.458	11.423.789	11.879.249	12.344.046	12.818.372	12.993.586	13.178.703	13.373.967	13.579.564	13.795.708
Net Book Value		10.889.812	10.891.560	10.893.760	10.895.830	10.897.910	11.208.900	11.519.913	11.830.971	12.142.075	12.453.225
CA Depr		128.510	137.476	146.625	155.962	165.490	175.214	185.137	195.264	205.598	216.143
Cum CA Depr		248.235	385.986	284.301	302.587	321.452	340.705	360.351	380.401	400.861	421.741

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Distribution Plant

		2008	2009	2010	2011	Cumulative
Structures and Improvements						
	Equity					
1 Original Cost (Bal.) Capital Adds		538,103	549,134	560,391	571,880	26,468,441
2 Cumulative Investment		26,767,016	27,316,170	27,876,561	28,448,441	
3 Depreciation of OC and Capital Additions						
	1981					
	1982	6,393	6,393	6,393	6,393	
	1983	6,525	6,525	6,525	6,525	
	1984	6,660	6,660	6,660	6,660	
	1985	6,798	6,798	6,798	6,798	
	1986	6,939	6,939	6,939	6,939	
	1987	7,083	7,083	7,083	7,083	
	1988	7,229	7,229	7,229	7,229	
	1989	7,379	7,379	7,379	7,379	
	1990	7,532	7,532	7,532	7,532	
	1991	7,687	7,687	7,687	7,687	
	1992	7,847	7,847	7,847	7,847	
	1993	8,009	8,009	8,009	8,009	
	1994	8,175	8,175	8,175	8,175	
	1995	8,344	8,344	8,344	8,344	
	1996	8,517	8,517	8,517	8,517	
	1997	8,609	8,609	8,609	8,609	
	1998	8,785	8,785	8,785	8,785	
	1999	8,966	8,966	8,966	8,966	
	2000	9,149	9,149	9,149	9,149	
	2001	9,337	9,337	9,337	9,337	
	2002	9,528	9,528	9,528	9,528	
	2003	9,724	9,724	9,724	9,724	
	2004	9,923	9,923	9,923	9,923	
	2005	10,126	10,126	10,126	10,126	
	2006	10,334	10,334	10,334	10,334	
	2007	10,546	10,546	10,546	10,546	
	2008	10,816	10,816	10,816	10,816	
	2009		10,983	10,983	10,983	
	2010			11,208	11,208	
	2011				11,436	
	Accmd Depr [8,632,528]	232,959	243,942	255,150	266,587	14,794,345
	Curent Depr	14,028,667	14,272,609	14,527,758	14,794,345	
Net Book Value		12,738,349	13,043,561	13,348,803	13,674,095	13,674,095
	CA Depr	232,959	243,942	255,150	266,587	
	Cum CA Depr	449,103	476,901	499,092	521,737	

Workpapers

CALCUALTION OF NET BOOK VALUE AS OF YEAR END 1996 2001-2011

Distribution Plant

Station Equipment		1981	1982	1982	1981	1992	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
		Service Life	Depr Rate	Escalation	Avg Age	1981 Avg Remain Life		Customer Growth Factor										Escalation
	Inputs	22	4.55%*	3.50%*	13	9												2.50%
1 Original Cost 1981/Capital Adds		35,125,517	1,632,496	1,730,226	1,811,638	1,896,868	1,986,107	2,079,544	2,177,377	2,279,813	2,387,067	2,499,368	2,616,952	2,740,068	2,868,975	3,003,948	3,145,270	3,261,422
2 Cumulative Investment		36,778,013	38,508,231	40,319,989	42,216,757	44,202,863	46,282,407	48,459,784	50,739,597	53,126,664	55,626,032	58,242,984	60,963,052	63,852,027	66,853,975	70,004,245	73,262,666	
3 Depreciation of OC and C apital Additions																		
	1981		1,596,614	1,596,614	1,596,614	1,596,614	1,596,614	1,596,614	1,596,614	1,596,614	1,596,614	0	0	0	0	0	0	0
	1982		75,113	75,113	75,113	75,113	75,113	75,113	75,113	75,113	75,113	75,113	75,113	75,113	75,113	75,113	75,113	75,113
	1983			78,647	78,647	78,647	78,647	78,647	78,647	78,647	78,647	78,647	78,647	78,647	78,647	78,647	78,647	78,647
	1984				82,347	82,347	82,347	82,347	82,347	82,347	82,347	82,347	82,347	82,347	82,347	82,347	82,347	82,347
	1985					86,221	86,221	86,221	86,221	86,221	86,221	86,221	86,221	86,221	86,221	86,221	86,221	86,221
	1986						90,278	90,278	90,278	90,278	90,278	90,278	90,278	90,278	90,278	90,278	90,278	90,278
	1987							94,525	94,525	94,525	94,525	94,525	94,525	94,525	94,525	94,525	94,525	94,525
	1988								98,972	98,972	98,972	98,972	98,972	98,972	98,972	98,972	98,972	98,972
	1989									103,628	103,628	103,628	103,628	103,628	103,628	103,628	103,628	103,628
	1990										108,503	108,503	108,503	108,503	108,503	108,503	108,503	108,503
	1991											113,608	113,608	113,608	113,608	113,608	113,608	113,608
	1992											118,952	118,952	118,952	118,952	118,952	118,952	118,952
	1993												124,549	124,549	124,549	124,549	124,549	124,549
	1994													130,408	130,408	130,408	130,408	130,408
	1995														136,543	136,543	136,543	136,543
	1996															142,967	142,967	142,967
	1997																149,696	149,696
	1998																	
	1999																	
	2000																	
	2001																	
	2002																	
	2003																	
	2004																	
	2005																	
	2006																	
	2007																	
	2008																	
	2009																	
	2010																	
	2011																	
Annual Depr	20,755,967	0	1,671,728	1,750,375	1,822,722	1,918,943	2,009,221	2,103,746	2,202,717	2,306,345	2,414,818	931,842	1,050,794	1,175,342	1,305,750	1,442,294	1,585,260	1,733,507
Cumm Depr		20,755,967	22,427,715	24,178,090	26,000,812	27,929,756	29,938,977	32,042,723	34,245,440	36,551,785	38,966,634	39,898,475	40,949,269	42,124,612	43,430,362	44,872,656	46,457,916	48,191,423
Net Book Value		14,369,550	14,350,598	14,330,161	14,309,077	14,287,001	14,263,887	14,239,685	14,214,344	14,187,811	14,160,030	15,727,557	17,293,715	18,858,440	20,421,663	21,983,319	23,543,329	25,071,243
CA Depr		0	75,113	153,761	236,108	322,329	412,607	507,131	606,103	709,731	818,234	931,842	1,050,794	1,175,342	1,305,750	1,442,294	1,585,260	1,733,507
Cum CA Depr		0	75,113	228,874	389,968	558,437	734,936	919,738	1,113,234	1,315,834	1,527,965	1,750,076	1,982,636	2,226,136	2,481,093	2,748,088	3,027,554	3,318,767

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Distribution Plant

Station Equipment

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
1 Original Cost 1931 Capital Additions	3,413,374	3,572,406	3,720,348	3,913,404	4,095,357	4,286,163	4,485,859	4,694,860	4,913,597	5,142,526
2 Cumulative Investment	76,676,040	80,248,447	83,967,295	87,900,339	91,995,696	96,281,859	100,767,719	105,462,578	110,376,176	115,518,702
3 Depreciation of OC and Capital Additions										
1981	0	0	0	0	0					
1982	75,113	75,113	75,113	75,113	75,113	75,113	0	0	0	0
1983	78,647	78,647	78,647	78,647	78,647	78,647	78,647	0	0	0
1984	82,347	82,347	82,347	82,347	82,347	82,347	82,347	82,347	0	0
1985	86,221	86,221	86,221	86,221	86,221	86,221	86,221	86,221	86,221	0
1986	90,278	90,278	90,278	90,278	90,278	90,278	90,278	90,278	90,278	90,278
1987	94,525	94,525	94,525	94,525	94,525	94,525	94,525	94,525	94,525	94,525
1988	98,972	98,972	98,972	98,972	98,972	98,972	98,972	98,972	98,972	98,972
1989	103,628	103,628	103,628	103,628	103,628	103,628	103,628	103,628	103,628	103,628
1990	108,503	108,503	108,503	108,503	108,503	108,503	108,503	108,503	108,503	108,503
1991	113,608	113,608	113,608	113,608	113,608	113,608	113,608	113,608	113,608	113,608
1992	118,952	118,952	118,952	118,952	118,952	118,952	118,952	118,952	118,952	118,952
1993	124,549	124,549	124,549	124,549	124,549	124,549	124,549	124,549	124,549	124,549
1994	130,408	130,408	130,408	130,408	130,408	130,408	130,408	130,408	130,408	130,408
1995	136,543	136,543	136,543	136,543	136,543	136,543	136,543	136,543	136,543	136,543
1996	142,967	142,967	142,967	142,967	142,967	142,967	142,967	142,967	142,967	142,967
1997	148,246	148,246	148,246	148,246	148,246	148,246	148,246	148,246	148,246	148,246
1998	155,153	155,153	155,153	155,153	155,153	155,153	155,153	155,153	155,153	155,153
1999		162,382	162,382	162,382	162,382	162,382	162,382	162,382	162,382	162,382
2000			169,948	169,948	169,948	169,948	169,948	169,948	169,948	169,948
2001				177,866	177,866	177,866	177,866	177,866	177,866	177,866
2002					186,153	186,153	186,153	186,153	186,153	186,153
2003						194,826	194,826	194,826	194,826	194,826
2004							203,903	203,903	203,903	203,903
2005								213,403	213,403	213,403
2006									223,345	223,345
2007										233,754
2008										
2009										
2010										
2011										
Annual Depr [29,755,987]	1,888,660	2,051,042	2,220,990	2,398,856	2,585,008	2,779,834	2,908,623	3,043,378	3,184,377	3,331,907
Cumm Depr	50,080,043	52,131,125	54,352,115	56,750,971	59,335,979	62,115,813	65,024,436	68,067,814	71,252,191	74,584,097
Net Book Value	26,595,997	28,117,322	29,615,180	31,149,369	32,659,717	34,166,047	35,743,283	37,394,764	39,123,985	40,934,605
CA Depr	1,888,660	2,051,042	2,220,990	2,398,856	2,585,008	2,779,834	2,908,623	3,043,378	3,184,377	3,331,907
Cum CA Depr	3,822,167	3,939,702	4,272,032	4,619,845	4,983,664	5,361,842	5,688,457	5,952,001	6,227,755	6,516,783

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Distribution Plant

		2008	2009	2010	2011	Cumulative
Station Equipment						
	Inputs					
1 Unadjusted Cost DSIS - Capital Adds		5,162,121	3,612,879	5,995,320	6,169,989	148,599,011
2 Cumulative Investment		120,900,823	126,533,703	132,429,023	138,599,011	
3 Depreciation of OC and Capital Additions						
	1981					
	1982	0	0	0	0	
	1983	0	0	0	0	
	1984	0	0	0	0	
	1985	0	0	0	0	
	1986	0	0	0	0	
	1987	94,525	0	0	0	
	1988	96,972	96,972	0	0	
	1989	103,628	103,628	103,628	0	
	1990	108,503	108,503	108,503	108,503	
	1991	113,608	113,608	113,608	113,608	
	1992	118,952	118,952	118,952	118,952	
	1993	124,549	124,549	124,549	124,549	
	1994	130,408	130,408	130,408	130,408	
	1995	136,543	136,543	136,543	136,543	
	1996	142,967	142,967	142,967	142,967	
	1997	148,246	148,246	148,246	148,246	
	1998	155,152	155,152	155,152	155,153	
	1999	162,382	162,382	162,382	162,382	
	2000	169,948	169,948	169,948	169,948	
	2001	177,866	177,866	177,866	177,866	
	2002	186,153	186,153	186,153	186,153	
	2003	194,826	194,826	194,826	194,826	
	2004	203,903	203,903	203,903	203,903	
	2005	213,403	213,403	213,403	213,403	
	2006	223,345	223,345	223,345	223,345	
	2007	233,751	233,751	233,751	233,751	
	2008	244,642	244,642	244,642	244,642	
	2009		256,040	256,040	256,040	
	2010			267,969	267,969	
	2011				280,454	
	Accrued Depr [20,755,967]	2,486,271	3,617,786	3,816,784	3,993,610	89,528,548
	Cumm Depr	78,070,368	81,718,154	85,534,938	89,528,548	
Net Book Value		42,830,455	44,815,548	46,894,085	49,070,464	49,070,464
	CA Depr	3,486,271	3,617,786	3,816,784	3,993,610	
	Cum CA Depr	6,818,177	7,134,057	7,464,370	7,810,193	

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CALCUALTION OF NET BOOK VALUE AS OF YEAR END 1996 2001-2011

Distribution Plant

Poles, Towers and Fixtures		1981 Service Life	1982 Depr Rate	1983 Escalation	1984 Avg Age	1985 1981 Avg Remaining Life	1986	1987 Customer Growth Factors	1988	1989 Cost Growth	1990	1991	1992	1993	1994	1995	1996	1997 Escalation
	Inputs	25	4.00%	3.50%	12	13		50.0%	50.0%	28.46%								2.50%
								(Cum Growth)	(Cus Growth)									
1 Original Cost 1981 Capital Adds		10.894.108	435.764	469.688	489.133	509.383	530.472	552.433	575.304	599.122	623.925	649.756	676.656	704.669	733.843	764.224	795.863	820.803
2 Cumulative Investment Replacements			11.347.124	11.816.812	12.303.945	12.813.329	13.343.801	13.896.234	14.471.538	15.070.660	15.694.585	16.344.341	17.020.997	17.725.666	18.459.508	19.223.732	20.019.594	20.840.398
3 New Customers - Avg Inputs for Account			947	947	947	947	947	947	947	947	947	947	947	947	947	947	947	947
4 Annual Capital Additions - New Customers		90 975	172.289	178 320	184 561	191 020	197.706	204 626	211.788	219.200	226.872	234.813	243.031	251.537	260.341	269.453	278.884	288.645
5 Cumulative Capital Additions - New Customers			172.289	350.609	535.170	726.190	923.896	1.128.522	1.340.309	1.559.510	1.786.382	2.021.194	2.264.226	2.515.763	2.776.104	3.045.557	3.324.441	3.613.086
6 Depreciation of OC and Capital Additions																		
	1981		435.764	435.764	435.764	435.764	435.764	435.764	435.764	435.764	435.764	435.764	435.764	435.764	435.764	435.764	0	0
	1982		24.932	24.932	24.932	24.932	24.932	24.932	24.932	24.932	24.932	24.932	24.932	24.932	24.932	24.932	24.932	24.932
	1983			25.920	25.920	25.920	25.920	25.920	25.920	25.920	25.920	25.920	25.920	25.920	25.920	25.920	25.920	25.920
	1984			26.948	26.948	26.948	26.948	26.948	26.948	26.948	26.948	26.948	26.948	26.948	26.948	26.948	26.948	26.948
	1985				28.016	28.016	28.016	28.016	28.016	28.016	28.016	28.016	28.016	28.016	28.016	28.016	28.016	28.016
	1986					29.127	29.127	29.127	29.127	29.127	29.127	29.127	29.127	29.127	29.127	29.127	29.127	29.127
	1987							30.282	30.282	30.282	30.282	30.282	30.282	30.282	30.282	30.282	30.282	30.282
	1988								31.484	31.484	31.484	31.484	31.484	31.484	31.484	31.484	31.484	31.484
	1989									32.733	32.733	32.733	32.733	32.733	32.733	32.733	32.733	32.733
	1990										34.032	34.032	34.032	34.032	34.032	34.032	34.032	34.032
	1991											35.383	35.383	35.383	35.383	35.383	35.383	35.383
	1992												36.787	36.787	36.787	36.787	36.787	36.787
	1993													38.248	38.248	38.248	38.248	38.248
	1994														39.767	39.767	39.767	39.767
	1995															41.347	41.347	41.347
	1996																42.990	42.990
	1997																	44.378
	1998																	
	1999																	
	2000																	
	2001																	
	2002																	
	2003																	
	2004																	
	2005																	
	2006																	
	2007																	
	2008																	
	2009																	
	2010																	
	2011																	
	Annual Depr 5.229.172	0	460.697	486.617	513.565	541.581	570.708	600.990	632.474	665.207	699.239	734.621	771.409	809.657	849.424	455.007	497.997	542.375
	Cumm Depr	5.229.172	5.689.869	6.176.485	6.690.050	7.231.631	7.802.339	8.403.329	9.035.803	9.701.009	10.400.248	11.134.870	11.906.278	12.715.936	13.565.360	14.020.367	14.518.364	15.060.739
Net Book Value			5.664.936	5.827.345	5.988.936	6.149.065	6.307.808	6.465.338	6.621.427	6.776.045	6.929.160	7.080.719	7.230.666	7.378.944	7.525.493	7.670.252	8.248.922	8.025.671	9.392.744
	CA Depr	0	74.932	50.453	77.860	105.816	134.944	165.726	196.710	229.442	263.474	298.857	335.643	373.893	413.660	455.007	497.997	542.375
	Cum CA Depr	0	24.932	75.385	128.653	182.617	240.760	300.169	361.935	426.152	492.917	562.231	634.202	708.537	787.553	868.667	933.004	1.000.372

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Distribution Plant

Poles, Towers and Fixtures (Input)	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
1 Original Cost 1981 Capital Adds	851,456	889,489	927,958	961,922	1,003,443	1,044,581	1,087,412	1,131,996	1,178,408	1,226,723
2 Cumulative Investment Replacements	21,690,854	22,580,343	23,508,301	24,470,224	25,473,667	26,522,251	27,609,663	28,741,660	29,920,068	31,146,790
3 New Customers - Avg Input for Account	947	947	947	947	947	947	947	947	947	947
4 Annual Capital Additions - New Customers	298,787	309,204	320,026	331,227	342,819	354,818	367,237	380,090	393,393	407,162
5 Cumulative Capital Additions - New Customers	3,911,833	4,221,037	4,541,063	4,872,289	5,215,108	5,569,927	5,937,163	6,317,253	6,710,647	7,117,809
6 Depreciation of OC and Capital Additions:										
1981	0	0	0	0	0	0	0	0	0	0
1982	24,932	24,932	24,932	24,932	24,932	24,932	24,932	24,932	24,932	24,932
1983	25,920	25,920	25,920	25,920	25,920	25,920	25,920	25,920	25,920	25,920
1984	26,948	26,948	26,948	26,948	26,948	26,948	26,948	26,948	26,948	26,948
1985	28,016	28,016	28,016	28,016	28,016	28,016	28,016	28,016	28,016	28,016
1986	29,127	29,127	29,127	29,127	29,127	29,127	29,127	29,127	29,127	29,127
1987	30,282	30,282	30,282	30,282	30,282	30,282	30,282	30,282	30,282	30,282
1988	31,484	31,484	31,484	31,484	31,484	31,484	31,484	31,484	31,484	31,484
1989	32,733	32,733	32,733	32,733	32,733	32,733	32,733	32,733	32,733	32,733
1990	34,032	34,032	34,032	34,032	34,032	34,032	34,032	34,032	34,032	34,032
1991	35,383	35,383	35,383	35,383	35,383	35,383	35,383	35,383	35,383	35,383
1992	36,787	36,787	36,787	36,787	36,787	36,787	36,787	36,787	36,787	36,787
1993	38,248	38,248	38,248	38,248	38,248	38,248	38,248	38,248	38,248	38,248
1994	39,767	39,767	39,767	39,767	39,767	39,767	39,767	39,767	39,767	39,767
1995	41,347	41,347	41,347	41,347	41,347	41,347	41,347	41,347	41,347	41,347
1996	42,990	42,990	42,990	42,990	42,990	42,990	42,990	42,990	42,990	42,990
1997	44,378	44,378	44,378	44,378	44,378	44,378	44,378	44,378	44,378	44,378
1998	46,128	46,128	46,128	46,128	46,128	46,128	46,128	46,128	46,128	46,128
1999		47,918	47,918	47,918	47,918	47,918	47,918	47,918	47,918	47,918
2000			49,839	49,839	49,839	49,839	49,839	49,839	49,839	49,839
2001				51,806	51,806	51,806	51,806	51,806	51,806	51,806
2002				-	53,851	53,851	53,851	53,851	53,851	53,851
2003					-	55,976	55,976	55,976	55,976	55,976
2004						-	58,186	58,186	58,186	58,186
2005							-	60,483	60,483	60,483
2006								-	62,872	62,872
2007									-	65,355
2008										
2009										
2010										
2011										
Annual Depr (- 5,229,172)	588,503	636,451	686,290	738,096	791,947	847,923	906,109	966,592	1,029,461	1,094,820
Cumm Depr	15,649,243	16,285,693	16,971,984	17,710,080	18,502,027	19,349,949	20,256,058	21,222,650	22,252,115	23,346,934
Net Book Value	9,957,445	10,519,686	11,079,380	11,636,433	12,190,749	12,742,228	13,290,769	13,836,263	14,378,600	14,917,665
CA Depr	588,503	636,451	686,290	738,096	791,947	847,923	906,109	966,592	1,029,461	1,094,820
Cum CA Depr	1,130,876	1,224,951	1,322,741	1,421,386	1,530,043	1,639,869	1,754,032	1,872,701	1,996,036	2,126,284

Distribution Plant

Poles, Towers and Fixtures [Inputs]

	2008	2009	2010	2011	Cumulative
1 Original Cost 1981 Capital Adds	1 277 018	1 329 376	1 383 801	1 440 620	36 577 605
2 Cumulative Investment Replacements	32 423 809	33 753 185	35 137 066	36 577 685	
3 Non Customer - Assigned for Account	947	947	947	947	
4 Annual Capital Additions - New Customers	425 433	436 162	451 838	467 228	8 891 039
5 Cumulative Capital Additions - New Customers	7 439 221	7 875 384	8 326 811	8 891 039	
6 Depreciation of OC and Capital Additions					
1981	0	0	0	0	
1982	21 932	0	0	0	
1983	25 920	25 920	0	0	
1984	26 918	26 918	26 918	0	
1985	28 016	28 016	28 016	28 016	
1986	29 127	29 127	29 127	29 127	
1987	30 282	30 282	30 282	30 282	
1988	31 484	31 484	31 484	31 484	
1989	32 733	32 733	32 733	32 733	
1990	34 032	34 032	34 032	34 032	
1991	35 383	35 383	35 383	35 383	
1992	36 787	36 787	36 787	36 787	
1993	38 248	38 248	38 248	38 248	
1994	39 767	39 767	39 767	39 767	
1995	41 347	41 347	41 347	41 347	
1996	42 990	42 990	42 990	42 990	
1997	44 378	44 378	44 378	44 378	
1998	46 128	46 128	46 128	46 128	
1999	47 948	47 948	47 948	47 948	
2000	49 839	49 839	49 839	49 839	
2001	51 806	51 806	51 806	51 806	
2002	53 851	53 851	53 851	53 851	
2003	55 976	55 976	55 976	55 976	
2004	58 186	58 186	58 186	58 186	
2005	60 483	60 483	60 483	60 483	
2006	62 872	62 872	62 872	62 872	
2007	65 355	65 355	65 355	65 355	
2008	67 937	67 937	67 937	67 937	
2009		70 622	70 622	70 622	
2010			73 412	73 412	
2011				76 314	
Annual Dept [5 229 172]	1 162 757	1 208 446	1 255 938	1 305 301	28 279 380
Cumm Dept	24 509 691	25 718 137	26 974 076	28 279 380	
Net Book Value	15 453 339	16 010 431	16 589 801	17 192 344	17 192 344
CA Dept	1 162 757	1 208 446	1 255 938	1 305 301	
Cum CA Dept	2 257 537	2 371 203	2 461 381	2 561 243	

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Workpapers

CALCUALTION OF NET BOOK VALUE AS OF YEAR END 1996-2001-2011

Distribution Plant

Overhead Conductors and Devices		1981 Service Life	1982 Depr Rate	1983 Escalation	1984 Avg Age	1985 1981 Avg Remaining Life	1986	1987 Customer Growth Factors	1988	1989 Cust Growth	1990	1991	1992	1993	1994	1995	1996	1997 Escalation
	Inputs	27	3.70%	3.50%	11	16		50.0%	100.0%	28.404								2.50%
								(Case Cmth)	(Cse Cmth)									
1 Original Cost 1981/ Capital Additions		9,446,881	362,130	376,012	390,426	405,392	420,932	437,068	453,822	471,219	489,282	508,038	527,513	547,734	568,731	590,532	613,169	630,522
2 Cumulative Investment Replacements			9,809,011	10,185,024	10,575,449	10,980,842	11,401,774	11,838,842	12,292,664	12,763,883	13,253,165	13,761,203	14,288,716	14,836,450	15,405,181	15,995,713	16,608,882	17,239,404
3 New Customers - Avg Inquiet for Account			917	947	947	947	947	947	947	947	947	947	947	947	947	947	947	947
4 Annual Capital Additions - New Customers		158 8	300 660	311,183	322 075	333,348	345,013	357,090	369,368	382,524	395,912	409,769	424,111	438,955	454,318	470,220	486,677	503,711
5 Cumulative Capital Additions - New Customers			300 668	611,844	933,919	1,267,266	1,612,281	1,969,371	2,338,960	2,721,484	3,117,396	3,527,165	3,951,276	4,390,231	4,844,550	5,314,769	5,801,447	6,305,158
6 Depreciation of OC and Capital Additions																		
	1981		349,686	349,686	349,686	349,686	349,686	349,686	349,686	349,686	349,686	349,686	349,686	349,686	349,686	349,686	349,686	349,686
	1982		24,548	24,548	24,548	24,548	24,548	24,548	24,548	24,548	24,548	24,548	24,548	24,548	24,548	24,548	24,548	24,548
	1983			25,452	25,452	25,452	25,452	25,452	25,452	25,452	25,452	25,452	25,452	25,452	25,452	25,452	25,452	25,452
	1984			26,389	26,389	26,389	26,389	26,389	26,389	26,389	26,389	26,389	26,389	26,389	26,389	26,389	26,389	26,389
	1985				27,361	27,361	27,361	27,361	27,361	27,361	27,361	27,361	27,361	27,361	27,361	27,361	27,361	27,361
	1986					28,368	28,368	28,368	28,368	28,368	28,368	28,368	28,368	28,368	28,368	28,368	28,368	28,368
	1987						29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413	29,413
	1988							30,497	30,497	30,497	30,497	30,497	30,497	30,497	30,497	30,497	30,497	30,497
	1989								31,620	31,620	31,620	31,620	31,620	31,620	31,620	31,620	31,620	31,620
	1990									32,785	32,785	32,785	32,785	32,785	32,785	32,785	32,785	32,785
	1991										33,993	33,993	33,993	33,993	33,993	33,993	33,993	33,993
	1992											35,245	35,245	35,245	35,245	35,245	35,245	35,245
	1993												36,544	36,544	36,544	36,544	36,544	36,544
	1994													37,891	37,891	37,891	37,891	37,891
	1995														39,287	39,287	39,287	39,287
	1996															40,735	40,735	40,735
	1997																42,235	42,235
	1998																	43,789
	1999																	
	2000																	
	2001																	
	2002																	
	2003																	
	2004																	
	2005																	
	2006																	
	2007																	
	2008																	
	2009																	
	2010																	
	2011																	
	Annual Depr	3,888,729	0	374,432	399,881	426,273	453,634	482,002	511,415	541,912	573,532	606,317	640,310	675,555	712,099	749,990	789,277	830,012	872,301
	Cmum Depr		3,888,729	4,223,161	4,623,043	5,049,318	5,502,952	5,984,954	6,496,369	7,038,281	7,611,813	8,218,130	8,858,440	9,533,995	10,246,095	10,996,085	11,785,362	12,615,374	13,490,356
Net Book Value			5,596,152	5,886,511	6,173,822	6,460,050	6,745,156	7,029,101	7,311,814	7,593,343	7,873,553	8,152,431	8,429,928	8,705,997	8,980,567	9,253,646	9,525,120	9,794,954	10,053,806
	CA Depr		0	24,548	49,999	76,388	103,749	132,118	161,531	192,028	223,648	256,433	290,425	325,671	362,215	400,106	439,393	480,128	525,497
	Cum CA Depr		0	24,548	74,547	126,388	180,138	235,867	293,648	353,558	415,675	480,000	546,858	616,096	687,886	762,320	839,498	919,520	1,005,625

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Holy Cross Energy

Overhead Conductors and Devices

Inputs

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
1 Original Cost FERC Capital Additions	624 459	679.301	705.092	741.860	779 643	788 482	818.415	859.184	881.733	915.206
2 Cumulative Investment Replacements	17 893 063	18 572 367	19.278 259	20 020 119	20 749 763	21 538 244	22.356.659	23.226.143	24.107.877	25.023.083
3 New Customers - Avg Import for Arrayed	947	947	947	947	947	947	947	947	947	947
4 Annual Capital Additions - New Customers	523 341	539 568	558 473	578 020	598 231	619 189	640.861	663.291	686 506	710 524
5 Cumulative Capital Additions - New Customers	6 626 499	7.366.066	7.924.540	8.502 560	9 100 830	9.720 020	10.360 881	11.024.172	11.710 678	12 421.203
6 Depreciation of Old and Capital Additions-										
1941	0	0	0	0	0	0	0	0	0	0
1942	24.548	24.548	24.548	24.548	24.548	24.548	24.548	24.548	24.548	24.548
1943	25.452	25.452	25.452	25.452	25.452	25.452	25.452	25.452	25.452	25.452
1944	26.389	26.389	26.389	26.389	26.389	26.389	26.389	26.389	26.389	26.389
1945	27.361	27.361	27.361	27.361	27.361	27.361	27.361	27.361	27.361	27.361
1946	28.368	28.368	28.368	28.368	28.368	28.368	28.368	28.368	28.368	28.368
1947	29.413	29.413	29.413	29.413	29.413	29.413	29.413	29.413	29.413	29.413
1948	30.497	30.497	30.497	30.497	30.497	30.497	30.497	30.497	30.497	30.497
1949	31.620	31.620	31.620	31.620	31.620	31.620	31.620	31.620	31.620	31.620
1950	32.785	32.785	32.785	32.785	32.785	32.785	32.785	32.785	32.785	32.785
1951	33.993	33.993	33.993	33.993	33.993	33.993	33.993	33.993	33.993	33.993
1952	35.245	35.245	35.245	35.245	35.245	35.245	35.245	35.245	35.245	35.245
1953	36.544	36.544	36.544	36.544	36.544	36.544	36.544	36.544	36.544	36.544
1954	37.891	37.891	37.891	37.891	37.891	37.891	37.891	37.891	37.891	37.891
1955	39.287	39.287	39.287	39.287	39.287	39.287	39.287	39.287	39.287	39.287
1956	40.735	40.735	40.735	40.735	40.735	40.735	40.735	40.735	40.735	40.735
1957	45.369	45.369	45.369	45.369	45.369	45.369	45.369	45.369	45.369	45.369
1958	47.032	47.032	47.032	47.032	47.032	47.032	47.032	47.032	47.032	47.032
1959		48.756	48.756	48.756	48.756	48.756	48.756	48.756	48.756	48.756
2000			50.543	50.543	50.543	50.543	50.543	50.543	50.543	50.543
2001				52.395	52.395	52.395	52.395	52.395	52.395	52.395
2002					54.316	54.316	54.316	54.316	54.316	54.316
2003						56.307	56.307	56.307	56.307	56.307
2004							58.371	58.371	58.371	58.371
2005								60.511	60.511	60.511
2006									62.730	62.730
2007										65.030
2008										
2009										
2010										
2011										
Arrayed Depr [3.818.729]	572.529	621.285	671.827	724.222	779.538	834.845	892.216	953.727	1.016.457	1.081.486
Cumm Depr	14.062.285	14.684.569	15.356.397	16.080.619	16.859.157	17.694.002	18.587.219	19.540.946	20.557.402	21.638.889
Net Book Value	10.657.077	11.254.681	11.846.422	12.432.060	13.011.436	13.584.262	14.150.321	14.709.370	15.261.153	15.805.407
CA Depr	572.529	621.285	671.827	724.222	779.538	834.845	892.216	953.727	1.016.457	1.081.486
Cum CA Depr	1.096.026	1.193.814	1.293.112	1.396.090	1.502.761	1.613.383	1.728.061	1.846.943	1.970.181	2.097.943

Distribution Plant

	2008	2009	2010	2011	Cumulative
Overhead Conductors and Devices					
[redacted]					
1 Original Cost 1981 Capital Additions	919.950	906.013	1,023,435	1,062,298	29,044,790
2 Cumulative Investment Replacements	25,973,033	26,959,017	27,982,492	29,014,790	
3 New Customers - Avg Import per Account	947	947	947	947	
4 Annual Capital Additions - New Customers	735,403	761,142	787,782	815,354	15,520,893
5 Cumulative Capital Additions - New Customers	13,156,615	13,917,757	14,705,539	15,520,893	
6 Depreciation of OH and Capital Additions					
1981	0	0	0	0	
1982	23,548	0	0	0	
1983	25,152	25,152	0	0	
1984	26,389	26,389	26,389	0	
1985	27,361	27,361	27,361	27,361	
1986	28,368	28,368	28,368	28,368	
1987	29,413	29,413	29,413	29,413	
1988	30,497	30,497	30,497	30,497	
1989	31,620	31,620	31,620	31,620	
1990	32,785	32,785	32,785	32,785	
1991	33,993	33,993	33,993	33,993	
1992	35,245	35,245	35,245	35,245	
1993	36,544	36,544	36,544	36,544	
1994	37,891	37,891	37,891	37,891	
1995	39,287	39,287	39,287	39,287	
1996	40,735	40,735	40,735	40,735	
1997	45,369	45,369	45,369	45,369	
1998	47,032	47,032	47,032	47,032	
1999	48,756	48,756	48,756	48,756	
2000	50,543	50,543	50,543	50,543	
2001	52,395	52,395	52,395	52,395	
2002	54,316	54,316	54,316	54,316	
2003	56,307	56,307	56,307	56,307	
2004	58,371	58,371	58,371	58,371	
2005	60,511	60,511	60,511	60,511	
2006	62,730	62,730	62,730	62,730	
2007	65,030	65,030	65,030	65,030	
2008	67,414	67,414	67,414	67,414	
2009		69,886	69,886	69,886	
2010			72,449	72,449	
2011				75,106	
Annual Depr [redacted]	1,148,900	1,194,239	1,241,236	1,289,953	26,513,218
Cumm Depr	25,187,749	25,982,028	25,223,265	26,513,218	
Net Book Value	16,341,859	16,894,776	17,464,767	18,052,466	18,052,466
CA Depr	1,148,900	1,194,239	1,241,236	1,289,953	
Cum CA Depr	2,230,887	2,343,119	2,435,475	2,531,190	

CALCUALTION OF NET BOOK VALUE AS OF YEAR END 1996 2001-2011

Distribution Plant

Undergound Cable		1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
		Service Life	Dept Base	Escalation	Avg Age	1981 Avg Remaining Life		Customer Growth Factors		Cust Growth								Escalation
	Inputs	58	1.75%	3.50%	9	49		50.0%	50.0%	28.404								2.50%
								(Cause Growth)	(Use Growth)									
1 Original Cost 1981 Capital Additions		61,819,238	1,157,402	1,178,036	1,199,078	1,220,475	1,242,234	1,264,422	1,286,903	1,309,951	1,333,327	1,357,120	1,381,338	1,405,980	1,431,072	1,456,615	1,482,630	1,494,484
2 Cumunlative Investment Replacements			66,016,690	67,194,693	68,393,771	69,614,246	70,856,503	72,120,925	73,407,910	74,717,862	76,051,189	77,408,309	78,789,647	80,195,635	81,626,712	83,083,327	84,565,934	86,060,419
3 New Customers - Avg Impact for Account			917	947	947	947	947	947	947	947	947	947	947	947	947	947	947	947
4 Annual Capital Additions - New Customers			107,276	111,031	114,917	118,939	123,102	127,410	131,870	136,485	141,263	146,206	151,324	156,620	162,102	167,775	173,647	179,725
5 Cumunlative Capital Additions - New Customers			107,276	218,307	333,224	452,163	575,265	702,675	834,545	971,030	1,112,292	1,258,499	1,409,822	1,566,442	1,728,544	1,896,319	2,069,966	2,249,691
																		1
6 Depreciation of OC and Capital Additions																		1
	1981		1,118,263	1,118,263	1,118,263	1,118,263	1,118,263	1,118,263	1,118,263	1,118,263	1,118,263	1,118,263	1,118,263	1,118,263	1,118,263	1,118,263	1,118,263	1,118,263
	1982		21,805	21,805	21,805	21,805	21,805	21,805	21,805	21,805	21,805	21,805	21,805	21,805	21,805	21,805	21,805	21,805
	1983			22,226	22,226	22,226	22,226	22,226	22,226	22,226	22,226	22,226	22,226	22,226	22,226	22,226	22,226	22,226
	1984				22,655	22,655	22,655	22,655	22,655	22,655	22,655	22,655	22,655	22,655	22,655	22,655	22,655	22,655
	1985					23,093	23,093	23,093	23,093	23,093	23,093	23,093	23,093	23,093	23,093	23,093	23,093	23,093
	1986						23,541	23,541	23,541	23,541	23,541	23,541	23,541	23,541	23,541	23,541	23,541	23,541
	1987							23,997	23,997	23,997	23,997	23,997	23,997	23,997	23,997	23,997	23,997	23,997
	1988								24,463	24,463	24,463	24,463	24,463	24,463	24,463	24,463	24,463	24,463
	1989									24,939	24,939	24,939	24,939	24,939	24,939	24,939	24,939	24,939
	1990										25,424	25,424	25,424	25,424	25,424	25,424	25,424	25,424
	1991											25,919	25,919	25,919	25,919	25,919	25,919	25,919
	1992												26,425	26,425	26,425	26,425	26,425	26,425
	1993													26,942	26,942	26,942	26,942	26,942
	1994														27,469	27,469	27,469	27,469
	1995															28,007	28,007	28,007
	1996																28,556	28,556
	1997																	28,866
	1998																	
	1999																	
	2000																	
	2001																	
	2002																	
	2003																	
	2004																	
	2005																	
	2006																	
	2007																	
	2008																	
	2009																	
	2010																	
	2011																	
Annual Dept	10,061,465		0	1,140,068	1,162,293	1,184,918	1,208,042	1,231,582	1,255,579	1,280,042	1,304,981	1,330,403	1,356,324	1,382,749	1,409,691	1,437,160	1,465,166	1,493,722	1,522,589
Cumm Dept			10,061,465	11,204,433	12,366,726	13,551,674	14,759,715	15,991,298	17,246,877	18,526,919	19,831,900	21,162,305	22,518,629	23,901,379	25,311,070	26,748,229	28,213,396	29,707,118	31,229,707
Net Book Value			54,794,873	51,919,484	55,046,277	55,175,323	55,306,696	55,440,470	55,576,723	55,715,536	55,856,992	56,001,176	56,148,179	56,298,091	56,451,007	56,607,027	56,766,250	56,928,783	57,080,403
CA Dept			0	21,805	44,010	66,636	89,779	113,319	137,317	161,780	186,718	212,142	238,062	264,487	291,428	318,897	346,901	375,460	404,585
Cumm CA Dept			0	21,805	65,815	110,716	156,464	203,098	250,636	299,096	348,498	398,860	450,204	502,548	555,915	610,325	665,800	722,363	779,785

Distribution Plant

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Underground Conduit										
Inputs										
1 Original Cost 1981 Capital Additions	1 520 895	1 537 771	1 575 126	1 602 962	1 631 291	1 660 119	1 689 458	1 719 335	1 749 769	1 780 620
2 Cumulative Investment Replacements	87 761 314	89 129 087	90 704 213	92 307 176	93 938 466	95 598 586	97 288 044	99 007 358	100 757 057	102 537 677
3 New Customers - Avg Inputs for Account	917	947	947	947	947	947	947	947	947	947
4 Annual Capital Additions - New Customers	186 015	192 526	199 264	206 239	213 457	220 928	228 660	236 663	244 947	253 520
5 Cumulative Capital Additions - New Customers	2 435 707	2 628 232	2 827 497	3 033 735	3 247 192	3 468 120	3 696 780	3 933 444	4 178 391	4 431 910
	2	3	4	5	6	7	8	9	10	11
6 Depreciation of Old and Capital Additions	2	3	4	5	6	7	8	9	10	11
1981	0	0	0	0	0	0	0	0	0	0
1982	21 805	21 805	21 805	21 805	21 805	21 805	21 805	21 805	21 805	21 805
1983	22 226	22 226	22 226	22 226	22 226	22 226	22 226	22 226	22 226	22 226
1984	22 655	22 655	22 655	22 655	22 655	22 655	22 655	22 655	22 655	22 655
1985	23 093	23 093	23 093	23 093	23 093	23 093	23 093	23 093	23 093	23 093
1986	23 541	23 541	23 541	23 541	23 541	23 541	23 541	23 541	23 541	23 541
1987	23 997	23 997	23 997	23 997	23 997	23 997	23 997	23 997	23 997	23 997
1988	24 463	24 463	24 463	24 463	24 463	24 463	24 463	24 463	24 463	24 463
1989	24 939	24 939	24 939	24 939	24 939	24 939	24 939	24 939	24 939	24 939
1990	25 424	25 424	25 424	25 424	25 424	25 424	25 424	25 424	25 424	25 424
1991	25 919	25 919	25 919	25 919	25 919	25 919	25 919	25 919	25 919	25 919
1992	26 425	26 425	26 425	26 425	26 425	26 425	26 425	26 425	26 425	26 425
1993	26 942	26 942	26 942	26 942	26 942	26 942	26 942	26 942	26 942	26 942
1994	27 469	27 469	27 469	27 469	27 469	27 469	27 469	27 469	27 469	27 469
1995	28 007	28 007	28 007	28 007	28 007	28 007	28 007	28 007	28 007	28 007
1996	28 556	28 556	28 556	28 556	28 556	28 556	28 556	28 556	28 556	28 556
1997	28 866	28 866	28 866	28 866	28 866	28 866	28 866	28 866	28 866	28 866
1998	29 429	29 429	29 429	29 429	29 429	29 429	29 429	29 429	29 429	29 429
1999		30 005	30 005	30 005	30 005	30 005	30 005	30 005	30 005	30 005
2000			30 593	30 593	30 593	30 593	30 593	30 593	30 593	30 593
2001				31 193	31 193	31 193	31 193	31 193	31 193	31 193
2002					31 806	31 806	31 806	31 806	31 806	31 806
2003						32 432	32 432	32 432	32 432	32 432
2004							33 071	33 071	33 071	33 071
2005								33 724	33 724	33 724
2006									34 390	34 390
2007										35 071
2008										
2009										
2010										
2011										
Annual Depr [10 064 365]	433 757	463 763	494 357	525 566	557 358	589 781	622 863	656 579	690 969	726 052
Cumm Depr	31 668 461	32 127 227	32 621 584	33 147 150	33 704 493	34 294 284	34 917 147	35 573 725	36 264 694	36 990 745
Net Book Value	58 353 557	59 630 093	60 910 126	62 193 776	63 481 165	64 772 422	66 067 677	67 367 067	68 670 734	69 978 822
CA Depr	433 755	463 760	494 353	525 566	557 352	589 781	622 855	656 579	690 969	726 041
Cum CA Depr	806 060	897 513	956 113	1 019 699	1 082 898	1 147 136	1 212 639	1 279 434	1 347 568	1 417 010

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Distribution Plant

	2008	2009	2010	2011	Cumulative
Underground Conduit					
[Input]					
1 Original Cost ESVE Capital Additions	1 812 010	1 854 112	1 876 702	1 909 868	109 980 446
2 Cumulative Investment Replacement-	101 319 766	106 193 878	108 070 580	109 980 448	
3 New Customers - Avg Install for Account	917	917	917	917	
4 Annual Capital Additions - New Customers	262 393	271 537	281 602	290 920	5 537 882
5 Cumulative Capital Additions - New Customers	4 694 303	4 965 840	5 246 962	5 537 882	
6 Depreciation of OC and Capital Additions	12	13	14	15	
	12	13	14	15	
1981	0	0	0	0	
1982	21 805	0	0	0	
1983	22 226	22 226	0	0	
1984	22 655	22 655	22 655	0	
1985	23 093	23 093	23 093	23 093	
1986	23 541	23 541	23 541	23 541	
1987	23 997	23 997	23 997	23 997	
1988	24 463	24 463	24 463	24 463	
1989	24 939	24 939	24 939	24 939	
1990	25 424	25 424	25 424	25 424	
1991	25 919	25 919	25 919	25 919	
1992	26 425	26 425	26 425	26 425	
1993	26 942	26 942	26 942	26 942	
1994	27 469	27 469	27 469	27 469	
1995	28 007	28 007	28 007	28 007	
1996	28 556	28 556	28 556	28 556	
1997	28 866	28 866	28 866	28 866	
1998	29 429	29 429	29 429	29 429	
1999	30 005	30 005	30 005	30 005	
2000	30 593	30 593	30 593	30 593	
2001	31 193	31 193	31 193	31 193	
2002	31 806	31 806	31 806	31 806	
2003	32 432	32 432	32 432	32 432	
2004	33 071	33 071	33 071	33 071	
2005	33 724	33 724	33 724	33 724	
2006	34 390	34 390	34 390	34 390	
2007	35 071	35 071	35 071	35 071	
2008	35 767	35 767	35 767	35 767	
2009		36 477	36 477	36 477	
2010			37 203	37 203	
2011				37 945	
Annual Depr [10 064 165]	761 819	776 490	791 872	806 767	40 127 312
Cumm Depr	37 752 585	38 529 078	39 320 549	40 127 312	
Net Book Value	71 291 484	72 630 680	73 996 993	75 391 018	75 391 018
CA Depr	761 807	776 490	791 858	806 717	
Cumm CA Depr	1 487 881	1 938 287	1 567 938	1 598 705	

CALCUALTION OF NET BOOK VALUE AS OF YEAR END 1996-2001-2011

Distribution Plant

Underground Conductors and Devices	Depr%	1981 Service Life 25	1982 Depr Rate 4.00%	1983 Escalation 2.50%	1984 Avg Age 7	1985 1981 Avg Remaining Life 18	1986	1987 Customer Growth Factors 50.0% (Same Growth)	1988 100.0% (Same Growth)	1989 Cust Growth 28.41%	1990	1991	1992	1993	1994	1995	1996	1997 Escalation 2.50%
1 Original Cost 1981- Capital Additions		48.446.955	2.005.783	2.088.822	2.175.299	2.265.357	2.359.142	2.456.811	2.558.523	2.664.446	2.774.754	2.889.629	3.009.259	3.133.842	3.263.584	3.398.696	3.539.402	3.650.370
2 Cumulative Investment Replacements			50.454.638	52.543.460	54.718.759	56.984.115	59.343.258	61.800.069	64.358.592	67.023.037	69.797.791	72.687.420	75.696.679	78.830.521	82.094.105	85.492.801	89.032.203	92.682.523
3 New Customers - Avg Invest for Accum			947	947	947	947	947	947	947	947	947	947	947	947	947	947	947	947
4 Annual Capital Additions - New Customers			455.945	471.904	488.820	505.515	523.208	541.520	560.473	580.090	600.393	621.407	643.156	665.667	688.965	713.079	738.036	761.864
5 Cumulative Capital Additions - New Customers			455.945	927.849	1.416.269	1.921.784	2.444.992	2.986.512	3.546.986	4.127.076	4.727.469	5.348.876	5.992.032	6.657.699	7.346.664	8.059.743	8.797.779	9.563.646
6 Depreciation of OC and Capital Additions																		
	1981		1.937.954	1.937.954	1.937.954	1.937.954	1.937.954	1.937.954	1.937.954	1.937.954	1.937.954	1.937.954	1.937.954	1.937.954	1.937.954	1.937.954	1.937.954	1.937.954
	1982		98.869	98.869	98.869	98.869	98.869	98.869	98.869	98.869	98.869	98.869	98.869	98.869	98.869	98.869	98.869	98.869
	1983			102.429	102.429	102.429	102.429	102.429	102.429	102.429	102.429	102.429	102.429	102.429	102.429	102.429	102.429	102.429
	1984				106.549	106.549	106.549	106.549	106.549	106.549	106.549	106.549	106.549	106.549	106.549	106.549	106.549	106.549
	1985					110.835	110.835	110.835	110.835	110.835	110.835	110.835	110.835	110.835	110.835	110.835	110.835	110.835
	1986						115.294	115.294	115.294	115.294	115.294	115.294	115.294	115.294	115.294	115.294	115.294	115.294
	1987							119.933	119.933	119.933	119.933	119.933	119.933	119.933	119.933	119.933	119.933	119.933
	1988								124.760	124.760	124.760	124.760	124.760	124.760	124.760	124.760	124.760	124.760
	1989									129.781	129.781	129.781	129.781	129.781	129.781	129.781	129.781	129.781
	1990										135.006	135.006	135.006	135.006	135.006	135.006	135.006	135.006
	1991											140.441	140.441	140.441	140.441	140.441	140.441	140.441
	1992												146.097	146.097	146.097	146.097	146.097	146.097
	1993													151.940	151.940	151.940	151.940	151.940
	1994														158.102	158.102	158.102	158.102
	1995															164.471	164.471	164.471
	1996																171.098	171.098
	1997																	176.568
	1998																	
	1999																	
	2000																	
	2001																	
	2002																	
	2003																	
	2004																	
	2005																	
	2006																	
	2007																	
	2008																	
	2009																	
	2010																	
	2011																	
Accrd Depr	13.565.679	0	2.036.423	2.138.852	2.245.401	2.356.236	2.471.530	2.591.463	2.716.223	2.846.005	2.981.010	3.121.452	3.267.548	3.419.529	3.577.631	3.742.102	3.913.199	4.089.767
Curum Depr		13.565.679	15.602.102	17.740.955	19.986.356	22.342.592	24.814.122	27.405.585	30.121.808	32.967.813	35.948.823	39.070.275	42.337.823	45.757.352	49.334.983	53.077.085	56.990.284	61.080.051
Net Book Value		34.881.276	35.300.481	35.730.354	36.188.672	36.563.308	36.974.128	37.380.996	37.783.769	38.182.300	38.576.437	38.966.020	39.350.887	39.730.868	40.105.785	40.475.458	40.839.698	41.168.119
CA Depr		0	98.869	200.698	307.447	418.202	533.376	653.509	778.269	908.050	1.043.056	1.183.498	1.329.594	1.481.575	1.639.677	1.804.148	1.975.245	2.151.813
Cum CA Depr		0	98.869	299.567	606.845	725.729	951.858	1.187.085	1.431.778	1.686.319	1.951.107	2.226.554	2.513.092	2.811.169	3.121.251	3.443.824	3.779.392	4.127.038

Distribution Plant

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Underground Conductors and Devices										
[type]										
1 Original Cost 1940 Capital Additions	3,799,983	3,953,784	4,117,970	4,286,807	4,462,566	4,645,531	4,835,998	5,034,274	5,240,679	5,455,547
2 Cumulative Investment Replacements	96,182,586	100,438,289	104,556,259	108,843,066	113,305,631	117,951,162	122,787,160	127,821,433	133,062,112	138,517,659
3 New Customers - Avg Investment Amount	937	947	947	947	947	947	947	947	947	947
4 Annual Capital Additions - New Customers	799,603	818,274	846,914	876,556	907,235	938,988	971,853	1,005,868	1,041,073	1,077,511
5 Cumulative Capital Additions - New Customers	10,352,250	11,170,524	12,017,438	12,893,993	13,801,229	14,740,217	15,712,070	16,717,938	17,759,012	18,836,522
6 Depreciation of OC and Capital Additions										
1981	1,937,954	1,937,954	1,937,954	0	0	0	0	0	0	0
1982	98,469	98,469	98,469	98,469	98,469	98,469	98,469	98,469	98,469	98,469
1981	102,429	102,429	102,429	102,429	102,429	102,429	102,429	102,429	102,429	102,429
1981	106,549	106,549	106,549	106,549	106,549	106,549	106,549	106,549	106,549	106,549
1987	110,835	110,835	110,835	110,835	110,835	110,835	110,835	110,835	110,835	110,835
1986	115,294	115,294	115,294	115,294	115,294	115,294	115,294	115,294	115,294	115,294
1987	119,933	119,933	119,933	119,933	119,933	119,933	119,933	119,933	119,933	119,933
1988	124,760	124,760	124,760	124,760	124,760	124,760	124,760	124,760	124,760	124,760
1989	129,781	129,781	129,781	129,781	129,781	129,781	129,781	129,781	129,781	129,781
1990	135,006	135,006	135,006	135,006	135,006	135,006	135,006	135,006	135,006	135,006
1991	140,441	140,441	140,441	140,441	140,441	140,441	140,441	140,441	140,441	140,441
1992	146,097	146,097	146,097	146,097	146,097	146,097	146,097	146,097	146,097	146,097
1993	151,980	151,980	151,980	151,980	151,980	151,980	151,980	151,980	151,980	151,980
1994	158,102	158,102	158,102	158,102	158,102	158,102	158,102	158,102	158,102	158,102
1995	165,471	165,471	165,471	165,471	165,471	165,471	165,471	165,471	165,471	165,471
1996	171,098	171,098	171,098	171,098	171,098	171,098	171,098	171,098	171,098	171,098
1997	176,568	176,568	176,568	176,568	176,568	176,568	176,568	176,568	176,568	176,568
1998	183,623	183,623	183,623	183,623	183,623	183,623	183,623	183,623	183,623	183,623
1999		190,962	190,962	190,962	190,962	190,962	190,962	190,962	190,962	190,962
2000			198,595	198,595	198,595	198,595	198,595	198,595	198,595	198,595
2001				206,534	206,534	206,534	206,534	206,534	206,534	206,534
2002					214,792	214,792	214,792	214,792	214,792	214,792
2003						223,381	223,381	223,381	223,381	223,381
2004							232,314	232,314	232,314	232,314
2005							241,606	241,606	241,606	241,606
2006								251,270	251,270	251,270
2007									261,322	
2008										
2009										
2010										
2011										
Accrual Depr [13,565,679]	4,273,390	4,464,353	4,662,948	2,931,528	3,146,220	3,369,701	3,602,015	3,843,621	4,094,891	4,356,213
Cumm Depr	65,353,481	69,817,793	74,480,741	77,412,269	80,558,590	83,928,291	87,530,306	91,373,926	95,468,817	99,825,030
Net Book Value	41,481,315	41,791,020	42,092,955	41,324,790	40,348,270	40,763,089	50,968,923	53,165,445	55,352,307	57,529,151
CA Depr	2,335,436	2,536,398	2,724,994	2,931,528	3,146,220	3,369,701	3,602,015	3,843,621	4,094,891	4,356,213
Cumm CA Depr	4,487,369	4,861,814	5,251,392	5,656,522	6,077,848	6,516,021	6,971,716	7,445,636	7,938,341	8,451,104

Distribution Plant

Underground Conductors and Devices

Inputs

	2008	2009	2010	2011	Cumulative
1 Original Cost 1981/ Capital Additions	5.679.224	5.912.072	6.154.467	6.406.800	162.670.222
2 Cumulative Investment Replacements	110.196.883	150.108.955	156.263.422	162.670.222	
3 New Customers - Avg Install for Account	947	947	947	947	
4 Annual Capital Additions - New Customers	1.113.224	1.154.257	1.194.656	1.236.469	23.537.127
5 Cumulative Capital Additions - New Customers	19.951.746	21.106.003	22.300.658	23.537.127	
6 Depreciation of OC and Capital Additions					
1981	0	0	0	0	
1982	0	0	0	0	
1983	102.129	0	0	0	
1984	106.349	106.349	0	0	
1985	110.835	110.835	110.835	0	
1986	115.594	115.594	115.594	115.594	
1987	119.933	119.933	119.933	119.933	
1988	124.760	124.760	124.760	124.760	
1989	129.781	129.781	129.781	129.781	
1990	135.006	135.006	135.006	135.006	
1991	140.441	140.441	140.441	140.441	
1992	146.097	146.097	146.097	146.097	
1993	151.980	151.980	151.980	151.980	
1994	158.102	158.102	158.102	158.102	
1995	164.471	164.471	164.471	164.471	
1996	171.098	171.098	171.098	171.098	
1997	176.768	176.768	176.768	176.768	
1998	183.623	183.623	183.623	183.623	
1999	190.962	190.962	190.962	190.962	
2000	198.595	198.595	198.595	198.595	
2001	206.534	206.534	206.534	206.534	
2002	214.792	214.792	214.792	214.792	
2003	223.381	223.381	223.381	223.381	
2004	232.314	232.314	232.314	232.314	
2005	241.606	241.606	241.606	241.606	
2006	251.270	251.270	251.270	251.270	
2007	261.322	261.322	261.322	261.322	
2008	271.778	271.778	271.778	271.778	
2009		282.653	282.653	282.653	
2010			293.965	293.965	
2011				305.731	
Accrual Depr [12.765.679]	4.529.322	4.709.746	4.897.162	5.092.058	119.053.518
Census Depr	108.354.552	109.064.298	113.961.860	119.053.518	
Net Book Value	59.794.077	62.150.660	64.602.621	67.153.032	67.153.032
CA Depr	4.529.322	4.709.746	4.897.162	5.092.058	
Count CA Depr	8.805.735	9.239.268	9.686.508	9.989.220	

CALCULATION OF NET BOOK VALUE AS OF YEAR END 1996-2001-2011

Distribution Plant

Line	Transformers		1981 Service Life	1982 Dep Rate	1983 Escalation	Avg Age	1985 1981 Avg Remaining Life	1986	1987 Customer Growth Factors		1988 Cust Growth	1989	1990	1991	1992	1993	1994	1995	1996	1997 Escalation
		Inputs	26	3.93%	3.50%	12.3	13.3		100.0% (Cum Cust%)	100.0% (Inc Cust%)	29.466									2.50%
1	Original Cost 1981 Capital Additions		31,070,347	1,226,829	1,286,075	1,327,570	1,390,504	1,445,857	1,503,413	1,563,260	1,625,490	1,690,197	1,757,480	1,827,441	1,900,187	1,975,879	2,054,682	2,136,763	2,195,845
2	Cumulative Investment Replacements			37,387,186	38,593,760	39,920,330	41,310,834	42,756,691	44,260,104	45,823,364	47,448,854	49,139,051	50,896,531	52,723,972	54,624,159	56,599,846	58,654,528	60,791,291	62,987,136	64,182,981
3	New Customers - Avg Inquiry for Account			1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894
4	Annual Capital Additions - New Customers			1,909,093	1,970,737	2,039,712	2,111,102	2,184,991	2,261,466	2,340,617	2,422,539	2,507,327	2,595,084	2,685,912	2,779,919	2,877,216	2,977,918	3,082,146	3,190,021
5	Cumulative Capital Additions - New Customers			1,909,093	3,879,830	5,914,543	8,025,645	10,210,636	12,472,102	14,812,719	17,235,257	19,742,585	22,337,669	25,023,581	27,803,499	30,680,715	33,658,634	36,740,779	39,930,800
6	Depreciation of HC and Capital Additions																			
	1981			1,195,013	1,195,013	1,195,013	1,195,013	1,195,013	1,195,013	1,195,013	1,195,013	1,195,013	1,195,013	1,195,013	1,195,013	1,195,013	1,195,013	597,507	0	0
	1982			120,805	120,805	120,805	120,805	120,805	120,805	120,805	120,805	120,805	120,805	120,805	120,805	120,805	120,805	120,805	120,805	120,805
	1983				123,262	123,262	123,262	123,262	123,262	123,262	123,262	123,262	123,262	123,262	123,262	123,262	123,262	123,262	123,262	123,262
	1984					129,884	129,884	129,884	129,884	129,884	129,884	129,884	129,884	129,884	129,884	129,884	129,884	129,884	129,884	129,884
	1985						134,677	134,677	134,677	134,677	134,677	134,677	134,677	134,677	134,677	134,677	134,677	134,677	134,677	134,677
	1986							139,648	139,648	139,648	139,648	139,648	139,648	139,648	139,648	139,648	139,648	139,648	139,648	139,648
	1987								144,803	144,803	144,803	144,803	144,803	144,803	144,803	144,803	144,803	144,803	144,803	144,803
	1988									150,149	150,149	150,149	150,149	150,149	150,149	150,149	150,149	150,149	150,149	150,149
	1989										155,693	155,693	155,693	155,693	155,693	155,693	155,693	155,693	155,693	155,693
	1990											161,443	161,443	161,443	161,443	161,443	161,443	161,443	161,443	161,443
	1991												167,406	167,406	167,406	167,406	167,406	167,406	167,406	167,406
	1992													173,590	173,590	173,590	173,590	173,590	173,590	173,590
	1993														180,004	180,004	180,004	180,004	180,004	180,004
	1994															186,656	186,656	186,656	186,656	186,656
	1995																193,574	193,574	193,574	193,574
	1996																	200,708	200,708	200,708
	1997																		215,595	215,595
	1998																			
	1999																			
	2000																			
	2001																			
	2002																			
	2003																			
	2004																			
	2005																			
	2006																			
	2007																			
	2008																			
	2009																			
	2010																			
	2011																			
	Annual Depr	[15,937,667]	0	1,315,818	1,441,080	1,570,961	1,703,642	1,843,289	1,990,093	2,140,242	2,295,935	2,457,378	2,624,785	2,798,375	2,978,379	3,165,035	2,761,082	2,369,781	2,579,878
	Cumm Depr		14,937,667	16,253,485	17,694,566	19,265,530	20,971,172	22,816,461	24,806,554	26,946,795	29,242,730	31,700,109	34,324,893	37,123,268	40,101,648	43,266,682	46,027,764	48,397,548	50,977,426
Net Book Value			16,132,680	17,957,794	19,733,525	21,579,543	23,375,508	23,161,066	26,935,852	28,699,487	30,451,581	32,191,727	33,919,506	35,634,484	37,336,211	39,024,231	41,295,540	44,149,669	46,959,656
	CA Depr		0	120,805	246,067	375,951	510,628	650,276	795,079	945,228	1,100,922	1,262,363	1,429,771	1,603,362	1,783,366	1,970,021	2,163,575	2,363,283	2,579,878
	Cum CA Depr		0	120,805	366,872	622,010	886,579	1,160,901	1,445,353	1,740,307	2,046,130	2,362,287	2,692,136	3,033,133	3,386,728	3,753,387	4,133,597	4,527,859	4,944,162

Distribution Plant

Line Transformers

[Inputs]

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
1 Original Cost 1981/ Capital Additions	2 266 569	2.376.713	2.470.410	2 567 801	2 669 023	2 774 253	2 883 623	2.997.304	3.115.467	3.238.269
2 Cumulative Investment Replacements	60.787.351	62 664.064	65.134.474	67.702.276	70.371.300	73.145.561	76.029.184	79.026.488	82.141.956	85.380.244
3 New Customers - Avg Install for Account	1.894	1.894	1.894	1.894	1.894	1.894	1.894	1.894	1.894	1.894
4 Annual Capital Additions - New Customers	3.301 671	3.417.210	3.536 833	3 660.622	3.788.744	3 921 350	4.058.597	4.200.648	4.347.671	4 499.839
5 Cumulative Capital Additions - New Customers	43.282.472	46.699 702	50.186 535	53 847.157	57.635.901	61.557.251	65.615.848	69.816.496	74.164.167	78.664 006
6 Depreciation of OC and Capital Additions										
1981	0	0	0	0	0	0	0	0	0	0
1982	120 805	120 805	120 805	120 805	120 805	120 805	120 805	120 805	120 805	120 805
1983	125 262	125 262	125 262	125 262	125 262	125 262	125 262	125 262	125 262	125 262
1984	129 884	129 884	129 884	129 884	129 884	129 884	129 884	129 884	129 884	129 884
1985	134 677	134 677	134 677	134 677	134 677	134 677	134 677	134 677	134 677	134 677
1986	139 618	139 618	139 618	139 618	139 618	139 618	139 618	139 618	139 618	139 618
1987	144 803	144 803	144 803	144 803	144 803	144 803	144 803	144 803	144 803	144 803
1988	150 149	150 149	150 149	150 149	150 149	150 149	150 149	150 149	150 149	150 149
1989	155 693	155 693	155 693	155 693	155 693	155 693	155 693	155 693	155 693	155 693
1990	161 443	161 443	161 443	161 443	161 443	161 443	161 443	161 443	161 443	161 443
1991	167 406	167 406	167 406	167 406	167 406	167 406	167 406	167 406	167 406	167 406
1992	173 590	173 590	173 590	173 590	173 590	173 590	173 590	173 590	173 590	173 590
1993	180 004	180 004	180 004	180 004	180 004	180 004	180 004	180 004	180 004	180 004
1994	186 656	186 656	186 656	186 656	186 656	186 656	186 656	186 656	186 656	186 656
1995	193 551	193 551	193 551	193 551	193 551	193 551	193 551	193 551	193 551	193 551
1996	200 708	200 708	200 708	200 708	200 708	200 708	200 708	200 708	200 708	200 708
1997	215 595	215 595	215 595	215 595	215 595	215 595	215 595	215 595	215 595	215 595
1998	223 530	223 530	223 530	223 530	223 530	223 530	223 530	223 530	223 530	223 530
1999		231 758	231 758	231 758	231 758	231 758	231 758	231 758	231 758	231 758
2000			240 290	240 290	240 290	240 290	240 290	240 290	240 290	240 290
2001				249 137	249 137	249 137	249 137	249 137	249 137	249 137
2002					258 311	258 311	258 311	258 311	258 311	258 311
2003						267 824	267 824	267 824	267 824	267 824
2004							277 689	277 689	277 689	277 689
2005								287 918	287 918	287 918
2006									298 526	298 526
2007										309 525
2008										
2009										
2010										
2011										
Accum Depr [14 937 667]	2 803 608	3 035 165	3 275 455	3 524 592	3 782 903	4 050 727	4 328 416	4 616 334	4 914 860	5 224 385
Curren Depr	53.775 333	56.810 499	60.085.954	63.610.516	67.393 449	71.444.176	75.772.592	80.388.927	85.303.786	90.528.171
Net Book Value	49.744.489	52.503.267	55.235.055	57 938 886	60.613.759	63.258.635	65.872.440	68.454.058	71.003 336	73.516.079
CA Depr	2.803 608	3.035 165	3.275 455	3 524 592	3.782 903	4.050 727	4.328 416	4.616 334	4 914 860	5.224 385
Cum CA Depr	5 383.286	5.838.573	6.310.621	6.800 047	7 307.495	7.833 630	8.379.143	8.944.750	9.531.191	10.139.244

Distribution Plant

	2008	2009	2010	2011	Cumulative
Line Transformers					
Inputs					
1 Original Cost DPIS Capital Additions	3 365 952	3 496 686	3 636 576	2 779 941	99 661 361
2 Cumulative Investment Replacements	88 746 196	92 244 815	95 881 420	99 661 361	
3 Num Customers - Avg Inquiry for Account	1 891	1 891	1 894	1 894	
4 Annual Capital Additions - New Customers	4 657 310	4 820 340	4 969 052	5 163 669	98 294 401
5 Cumulative Capital Additions - New Customers	83 321 310	88 141 680	93 110 732	98 294 401	
6 Depreciation of OC and Capital Additions					
1981	0	0	0	0	
1982	0	0	0	0	
1983	125 262	0	0	0	
1984	129 684	129 684	0	0	
1985	134 677	134 677	134 677	0	
1986	139 618	139 618	139 618	139 618	
1987	144 803	144 803	144 803	144 803	
1988	150 149	150 149	150 149	150 149	
1989	155 693	155 693	155 693	155 693	
1990	161 443	161 443	161 443	161 443	
1991	167 406	167 406	167 406	167 406	
1992	173 590	173 590	173 590	173 590	
1993	180 004	180 004	180 004	180 004	
1994	186 656	186 656	186 656	186 656	
1995	193 554	193 551	193 554	193 551	
1996	200 708	200 708	200 708	200 708	
1997	215 595	215 595	215 595	215 595	
1998	223 330	223 330	223 330	223 330	
1999	231 356	231 358	231 358	231 356	
2000	240 290	240 290	240 290	240 290	
2001	249 137	249 137	249 137	249 137	
2002	258 311	258 311	258 311	258 311	
2003	267 824	267 824	267 824	267 824	
2004	277 689	277 689	277 689	277 689	
2005	287 918	287 918	287 918	287 918	
2006	298 526	298 526	298 526	298 526	
2007	309 525	309 525	309 525	309 525	
2008	320 931	320 931	320 931	320 931	
2009		332 760	332 760	332 760	
2010			345 025	345 025	
2011				357 744	
Annual Depr [11 937 667]	5 424 581	5 632 009	5 847 350	6 070 217	111 502 078
Cumm Depr	95 932 042	101 564 051	107 411 841	113 502 058	
Net Book Value	36 114 851	78 001 834	81 790 382	84 453 704	84 453 704
CA Depr	5 424 581	5 632 009	5 847 350	6 070 217	
Cumul CA Depr	10 618 896	11 056 520	11 470 159	11 937 667	

CALCUALTION OF NET BOOK VALUE AS OF YEAR END 1996-2001-2011

Distribution Plant

Inputs		1981 Service Life 33 ft	1982 Depr Rate 2.70%	1984 Escalation 3.50%	1991 Avg Age 6.6	1983 1981 Avg Remaining Life 29.2	1986	1987 Customer Growth Factors 100.0%	1988 (Year Curve) 100.0%	1989 Cum Growth 28.401	1990	1991	1992	1993	1994	1995	1996	1997 Escalation 2.50%
1 Original Cost 1981/ Capital Additions		21,510,006	709,467	729,978	751,062	772,796	795,138	818,126	841,779	866,133	891,155	916,919	943,427	970,707	998,766	1,027,641	1,057,351	1,077,498
2 Cumulative Investment Replacements			33,719,470	25,979,450	26,730,532	27,503,328	28,298,467	29,116,593	29,958,371	30,824,496	31,715,641	32,632,560	33,576,987	34,549,689	35,545,455	36,573,096	37,620,447	38,707,855
3 New Customers - Avg Inquest for Account			1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894
4 Annual Capital Additions - New Customers			1,003,731	1,069,911	1,107,358	1,146,116	1,186,230	1,227,748	1,270,719	1,315,194	1,361,226	1,408,869	1,458,179	1,509,216	1,562,038	1,616,710	1,673,294	1,731,860
5 Cumulative Capital Additions - New Customers			1,033,731	2,103,642	3,211,000	4,357,116	5,543,346	6,771,094	8,041,813	9,357,007	10,718,233	12,127,102	13,585,282	15,094,497	16,656,535	18,273,245	19,946,539	21,678,399
6 Depreciation of OC and Capital Additions																		1
	1981		685,473	685,473	685,473	685,473	685,473	685,473	685,473	685,473	685,473	685,473	685,473	685,473	685,473	685,473	342,738	0
	1982		46,693	46,693	46,693	46,693	46,693	46,693	46,693	46,693	46,693	46,693	46,693	46,693	46,693	46,693	46,693	46,693
	1983			50,276	50,276	50,276	50,276	50,276	50,276	50,276	50,276	50,276	50,276	50,276	50,276	50,276	50,276	50,276
	1984				51,912	51,912	51,912	51,912	51,912	51,912	51,912	51,912	51,912	51,912	51,912	51,912	51,912	51,912
	1985					53,601	53,601	53,601	53,601	53,601	53,601	53,601	53,601	53,601	53,601	53,601	53,601	53,601
	1986						55,345	55,345	55,345	55,345	55,345	55,345	55,345	55,345	55,345	55,345	55,345	55,345
	1987							57,147	57,147	57,147	57,147	57,147	57,147	57,147	57,147	57,147	57,147	57,147
	1988								59,008	59,008	59,008	59,008	59,008	59,008	59,008	59,008	59,008	59,008
	1989									60,930	60,930	60,930	60,930	60,930	60,930	60,930	60,930	60,930
	1990										62,916	62,916	62,916	62,916	62,916	62,916	62,916	62,916
	1991											64,966	64,966	64,966	64,966	64,966	64,966	64,966
	1992												67,084	67,084	67,084	67,084	67,084	67,084
	1993													69,271	69,271	69,271	69,271	69,271
	1994														71,531	71,531	71,531	71,531
	1995															73,865	73,865	73,865
	1996																76,275	76,275
	1997																	78,471
	1998																	
	1999																	
	2000																	
	2001																	
	2002																	
	2003																	
	2004																	
	2005																	
	2006																	
	2007																	
	2008																	
	2009																	
	2010																	
	2011																	
	Annual Depr	4,524,135	0	784,168	783,444	816,356	869,957	945,302	1,002,449	1,061,458	1,122,368	1,185,304	1,250,270	1,317,354	1,386,623	1,458,156	1,189,261	922,821	1,001,293
	Cumm Depr		4,524,135	5,258,103	6,042,747	6,859,102	7,769,059	8,714,361	9,716,810	10,778,268	11,900,636	13,085,940	14,336,210	15,653,563	17,040,209	18,498,365	19,687,648	20,610,469	21,611,762
Net Book Value			29,015,871	21,021,901	22,010,346	23,062,430	24,091,386	25,127,452	26,170,876	27,221,916	28,280,827	29,347,914	30,423,432	31,507,685	32,600,978	33,703,626	35,158,693	36,966,517	38,774,492
	CA Depr		0	46,693	98,969	150,681	204,482	259,827	316,974	375,983	436,913	499,829	564,795	631,879	701,150	772,681	946,546	922,821	1,001,292
	Cum CA Depr		0	46,693	147,662	249,850	355,362	464,309	576,801	692,957	812,896	936,742	1,064,624	1,196,674	1,333,029	1,473,831	1,619,227	1,769,366	1,924,113

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Distribution Plant

Description	Inputs	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
1 Original Cost 1981 + Capital Additions		1.108.256	1.139.986	1.172.626	1.206.199	1.240.725	1.276.218	1.312.699	1.350.186	1.388.699	1.428.258
2 Cumulative Investment Replacements		19.486.111	19.956.097	42.128.723	43.114.922	44.575.657	45.851.915	47.164.714	48.515.101	49.904.150	51.332.970
3 New Customers - Avg Inquiries/Account		1.894	1.894	1.894	1.894	1.894	1.894	1.894	1.894	1.894	1.894
4 Annual Capital Additions - New Customers		1.792.475	1.855.211	1.920.144	1.987.349	2.056.906	2.128.898	2.203.409	2.280.526	2.360.347	2.442.959
5 Cumulative Capital Additions - New Customers		23.170.874	25.026.085	27.246.229	29.233.577	31.290.483	33.419.381	35.622.790	37.903.319	40.263.666	42.706.625
		2	3	4	5	6	7	8	9	10	11
6 Depreciation of OC and Capital Additions		2	3	4	5	6	7	8	9	10	11
	1981	0	0	0	0	0	0	0	0	0	0
	1982	18.693	18.693	18.693	18.693	18.693	18.693	18.693	18.693	18.693	18.693
	1983	50.276	50.276	50.276	50.276	50.276	50.276	50.276	50.276	50.276	50.276
	1984	51.912	51.912	51.912	51.912	51.912	51.912	51.912	51.912	51.912	51.912
	1985	53.601	53.601	53.601	53.601	53.601	53.601	53.601	53.601	53.601	53.601
	1986	55.345	55.345	55.345	55.345	55.345	55.345	55.345	55.345	55.345	55.345
	1987	57.147	57.147	57.147	57.147	57.147	57.147	57.147	57.147	57.147	57.147
	1988	59.008	59.008	59.008	59.008	59.008	59.008	59.008	59.008	59.008	59.008
	1989	60.930	60.930	60.930	60.930	60.930	60.930	60.930	60.930	60.930	60.930
	1990	62.916	62.916	62.916	62.916	62.916	62.916	62.916	62.916	62.916	62.916
	1991	64.966	64.966	64.966	64.966	64.966	64.966	64.966	64.966	64.966	64.966
	1992	67.084	67.084	67.084	67.084	67.084	67.084	67.084	67.084	67.084	67.084
	1993	69.271	69.271	69.271	69.271	69.271	69.271	69.271	69.271	69.271	69.271
	1994	71.531	71.531	71.531	71.531	71.531	71.531	71.531	71.531	71.531	71.531
	1995	73.865	73.865	73.865	73.865	73.865	73.865	73.865	73.865	73.865	73.865
	1996	76.275	76.275	76.275	76.275	76.275	76.275	76.275	76.275	76.275	76.275
	1997	78.471	78.471	78.471	78.471	78.471	78.471	78.471	78.471	78.471	78.471
	1998	81.026	81.026	81.026	81.026	81.026	81.026	81.026	81.026	81.026	81.026
	1999		83.665	83.665	83.665	83.665	83.665	83.665	83.665	83.665	83.665
	2000			86.390	86.390	86.390	86.390	86.390	86.390	86.390	86.390
	2001				89.205	89.205	89.205	89.205	89.205	89.205	89.205
	2002					92.113	92.113	92.113	92.113	92.113	92.113
	2003						95.116	95.116	95.116	95.116	95.116
	2004							98.218	98.218	98.218	98.218
	2005								101.422	101.422	101.422
	2006									104.732	104.732
	2007										108.150
	2008										
	2009										
	2010										
	2011										
	Annual Depr [1.521 13%]	1.062.370	1.165.986	1.252.373	1.341.761	1.433.697	1.528.814	1.627.033	1.729.456	1.833.189	1.941.360
	Cumm Depr	22.694.081	23.860.067	25.112.441	26.454.027	27.887.724	29.416.538	31.043.571	32.772.027	34.605.216	36.546.357
Net Book Value		40.597.903	42.422.115	44.262.508	46.114.473	47.978.416	49.854.259	51.743.934	53.646.392	55.562.600	57.493.039
	CA Depr	1.062.318	1.165.963	1.252.373	1.341.578	1.433.691	1.528.807	1.627.025	1.728.447	1.833.179	1.941.329
	Cumm CA Depr	2.083.640	2.248.200	2.418.255	2.592.951	2.775.269	2.962.498	3.153.832	3.355.472	3.561.626	3.774.508

Distribution Plant

Investors		2008	2009	2010	2011	Cumulative
	Inputs					
1 Original Cost 1981/ Capital Additions		1 169 729	1 511 809	1 555 094	1 599 619	57 469 221
2 Cumulative Investment Replacement		52 802 699	54 314 508	55 869 603	57 469 221	
3 New Customers - Avg Input for Account		1 894	1 894	1 894	1 894	
4 Annual Capital Additions - New Customers		2 528 863	2 616 959	2 708 552	2 803 352	53 363 950
5 Cumulative Capital Additions - New Customers		49 235 087	47 852 016	50 560 599	53 363 950	
6 Depreciation of OC and Capital Additions		12	13	14	15	
	1981	0	0	0	0	
	1982	0	0	0	0	
	1983	50 276	0	0	0	
	1984	51 912	51 912	0	0	
	1985	53 601	53 601	53 601	0	
	1986	55 345	55 345	55 345	55 345	
	1987	57 147	57 147	57 147	57 147	
	1988	59 008	59 008	59 008	59 008	
	1989	60 930	60 930	60 930	60 930	
	1990	62 916	62 916	62 916	62 916	
	1991	64 966	64 966	64 966	64 966	
	1992	67 084	67 084	67 084	67 084	
	1993	69 271	69 271	69 271	69 271	
	1994	71 531	71 531	71 531	71 531	
	1995	73 865	73 865	73 865	73 865	
	1996	76 275	76 275	76 275	76 275	
	1997	78 471	78 471	78 471	78 471	
	1998	81 026	81 026	81 026	81 026	
	1999	83 665	83 665	83 665	83 665	
	2000	86 390	86 390	86 390	86 390	
	2001	89 205	89 205	89 205	89 205	
	2002	92 113	92 113	92 113	92 113	
	2003	95 116	95 116	95 116	95 116	
	2004	98 218	98 218	98 218	98 218	
	2005	101 422	101 422	101 422	101 422	
	2006	101 732	104 732	104 732	104 732	
	2007	108 150	108 150	108 150	108 150	
	2008	111 681	111 681	111 681	111 681	
	2009		115 329	115 329	115 329	
	2010			119 096	119 096	
	2011				122 988	
	Annual Depr [4 321 135]		2 004 330	2 069 383	2 136 569	2 205 957	44 962 796
	Cumm Depr		38 550 886	40 620 270	42 756 839	44 962 796	
Net Book Value			59 406 900	61 566 285	63 673 362	65 870 375	65 870 375
	CA Depr		2 001 318	2 069 170	2 136 555	2 205 912	
	Cum CA Depr		3 935 617	4 073 688	4 205 925	4 342 497	

CALCUALTION OF NET BOOK VALUE AS OF YEAR END 1996 2001-2011

Distribution Plant

Meters		1981 Service Life	1982 Depr Rate	1983 Escalation	1984 Avg Age	1985 1981 Avg Remaining Life	1986	1987 Customer Growth Factors		1988 Cust Growth	1989	1990	1991	1992	1993	1994	1995 Service Life	1996 Depr Rate	1997 Escalation
	Inputs	32	3.13%	3.50%	11	21		100.0%	100.0%	28.404							32	3.13%	3.50%
								(Cust Coeffs)	(Inv Coeffs)										
1 Original Cost 1981 Capital Additions		11,352,350	367,178	379,053	391,313	403,970	417,036	430,524	444,449	458,824	473,664	488,985	504,800	521,127	537,982	555,383	573,348	588,171	
2 Cumulative Investment Replacements			11,719,528	12,098,581	12,489,895	12,893,865	13,310,900	13,741,425	14,185,874	14,644,698	15,118,362	15,607,348	16,112,148	16,633,275	17,171,257	17,726,640	18,299,988	18,886,158	
3 New Customers - Avg Investfor Account			1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894	1,894	
4 Annual Capital Additions - New Customers			196,158	202,624	210,130	217,484	223,096	232,975	241,129	249,568	258,203	267,344	278,301	286,385	298,409	308,703	317,521	328,816	
5 Cumulative Capital Additions - New Customers			196,158	398,782	609,312	826,797	1,050,893	1,284,868	1,525,997	1,775,565	2,033,769	2,301,212	2,579,513	2,864,299	3,160,708	3,467,491	3,785,012	4,113,646	
6 Depreciation of OL and Capital Additions																			
	1981		354,761	354,761	354,761	354,761	354,761	354,761	354,761	354,761	354,761	354,761	354,761	354,761	354,761	354,761	354,761	354,761	
	1982			17,601	17,601	17,601	17,601	17,601	17,601	17,601	17,601	17,601	17,601	17,601	17,601	17,601	17,601	17,601	
	1983				18,190	18,190	18,190	18,190	18,190	18,190	18,190	18,190	18,190	18,190	18,190	18,190	18,190	18,190	
	1984					18,795	18,795	18,795	18,795	18,795	18,795	18,795	18,795	18,795	18,795	18,795	18,795	18,795	
	1985						19,420	19,420	19,420	19,420	19,420	19,420	19,420	19,420	19,420	19,420	19,420	19,420	
	1986							20,067	20,067	20,067	20,067	20,067	20,067	20,067	20,067	20,067	20,087	20,087	
	1987								20,734	20,734	20,734	20,734	20,734	20,734	20,734	20,734	20,734	20,734	
	1988									21,424	21,424	21,424	21,424	21,424	21,424	21,424	21,424	21,424	
	1989										22,137	22,137	22,137	22,137	22,137	22,137	22,137	22,137	
	1990											22,874	22,874	22,874	22,874	22,874	22,874	22,874	
	1991												23,635	23,635	23,635	23,635	23,835	23,835	
	1992													24,422	24,422	24,422	24,422	24,422	
	1993														25,235	25,235	25,235	25,235	
	1994															26,075	26,075	26,075	
	1995																26,943	26,943	
	1996																	27,840	
	1997																		28,588
	1998																		
	1999																		
	2000																		
	2001																		
	2002																		
	2003																		
	2004																		
	2005																		
	2006																		
	2007																		
	2008																		
	2009																		
	2010																		
	2011																		
	Annual Depr 3,902,370	0	372,363	390,555	409,350	429,771	448,837	469,372	490,996	513,133	536,007	559,642	584,064	609,299	635,374	662,317	690,156	718,765	
	Cumm Depr	3,902,370	4,274,733	4,665,290	5,074,641	5,503,411	5,952,248	6,421,620	6,912,616	7,425,749	7,961,957	8,521,599	9,105,663	9,714,963	10,350,337	11,012,653	11,702,809	12,421,574	
Net Book Value		7,449,980	7,610,951	7,832,473	8,023,566	8,217,550	8,410,545	8,604,473	8,799,053	8,994,314	9,190,275	9,386,961	9,584,398	9,782,631	9,981,629	10,181,438	10,382,189	10,578,249	
Cost		307,224	309,108	310,592	312,076	314,760	316,644	318,528	320,412	322,296	324,180	326,064	327,948	329,832	331,716	333,600			
NBV Cost		24	25	25	26	26	27	27	27	28	28	29	29	30	30	31			
Percents			1.91%	1.89%	1.88%	1.78%	1.74%	1.70%	1.68%	1.67%	1.58%	1.53%	1.52%	1.49%	1.45%	1.43%			
	CA Depr	0	17,601	35,794	54,589	74,010	94,076	114,811	136,215	158,372	181,346	205,082	229,202	254,338	280,613	307,956	335,395	363,983	
	Cum CA Depr	0	17,601	53,395	90,383	128,599	168,086	208,897	251,046	294,607	339,619	386,128	434,185	483,842	535,151	588,169	642,951	699,378	

Distribution Fixed

Metrics	Input	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
1 Original Cost 1981/ Capital Additions		604.917	624.324	644.322	664.961	686.260	708.242	730.928	754.341	778.503	803.439
2 Cumulative Investment Replacements		19 491.105	20 115.429	20 759.752	21 424.713	22 110.973	22 819.215	23 550.143	24 304.484	25 082.986	25 886.426
3 New Customers - Avg Input for Account		1.894	1.894	1.894	1.894	1.894	1.894	1.894	1.894	1.894	1.894
4 Annual Capital Additions - New Customers		340.136	352.041	364.362	377.115	390.314	403.975	418.114	432.748	447.894	463.571
5 Cumulative Capital Additions - New Customers		4.451.702	4 805.823	5.170.185	5 547.300	5.937.614	6.341.589	6.759.703	7.192.451	7.640.345	8.103.916
		2	3	4	5	6	7	8	9	10	11
6 Depreciation of OC and Capital Additions		2	3	4	5	6	7	8	9	10	11
	1981	151.761	356.761	454.761	0	0	0	0	0	0	0
	1982	17.604	17.604	17.604	17.604	17.604	17.604	17.604	17.604	17.604	17.604
	1981	18.190	18.190	18.190	18.190	18.190	18.190	18.190	18.190	18.190	18.190
	1981	18.795	18.795	18.795	18.795	18.795	18.795	18.795	18.795	18.795	18.795
	1985	19.420	19.420	19.420	19.420	19.420	19.420	19.420	19.420	19.420	19.420
	1986	20.067	20.067	20.067	20.067	20.067	20.067	20.067	20.067	20.067	20.067
	1987	20.734	20.734	20.734	20.734	20.734	20.734	20.734	20.734	20.734	20.734
	1988	21.424	21.424	21.424	21.424	21.424	21.424	21.424	21.424	21.424	21.424
	1989	22.137	22.137	22.137	22.137	22.137	22.137	22.137	22.137	22.137	22.137
	1990	22.874	22.874	22.874	22.874	22.874	22.874	22.874	22.874	22.874	22.874
	1991	23.635	23.635	23.635	23.635	23.635	23.635	23.635	23.635	23.635	23.635
	1992	24.422	24.422	24.422	24.422	24.422	24.422	24.422	24.422	24.422	24.422
	1993	25.235	25.235	25.235	25.235	25.235	25.235	25.235	25.235	25.235	25.235
	1994	26.075	26.075	26.075	26.075	26.075	26.075	26.075	26.075	26.075	26.075
	1995	26.943	26.943	26.943	26.943	26.943	26.943	26.943	26.943	26.943	26.943
	1996	27.840	27.840	27.840	27.840	27.840	27.840	27.840	27.840	27.840	27.840
	1997	28.588	28.588	28.588	28.588	28.588	28.588	28.588	28.588	28.588	28.588
	1998	29.534	29.534	29.534	29.534	29.534	29.534	29.534	29.534	29.534	29.534
	1999		30.511	30.511	30.511	30.511	30.511	30.511	30.511	30.511	30.511
	2000			31.521	31.521	31.521	31.521	31.521	31.521	31.521	31.521
	2001				32.565	32.565	32.565	32.565	32.565	32.565	32.565
	2002					33.643	33.643	33.643	33.643	33.643	33.643
	2003						34.757	34.757	34.757	34.757	34.757
	2004							35.908	35.908	35.908	35.908
	2005								37.097	37.097	37.097
	2006									38.325	38.325
	2007										39.594
	2008										
	2009										
	2010										
	2011										
	Annual Depr	3 502 370	778.280	778.792	810.435	688.119	521.763	556.521	592.430	629.527	667.853	707.448
	Cumm Depr		13.169.834	13.948.626	14.758.941	15.247.060	15.768.823	16.325.345	16.917.774	17.547.302	18.215.155	18.922.603
Net Book Value			10.775.053	10.972.626	11.170.996	11.721.952	12.279.763	12.835.459	13.392.072	13.949.633	14.508.177	15.067.739
Cost												
NBV Cost												
Years co-to												
	CA Depr		493.517	424.028	455.550	488.114	521.757	556.514	592.422	629.518	667.843	707.437
	Cmu CA Depr		757.500	817.545	879.578	943.661	1.009.872	1.078.272	1.148.936	1.221.940	1.297.361	1.375.280

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Distribution Plant

Metres		2008	2009	2010	2011	Cumulative
	Inputs					
1 Original Cost 1941 Capital Additions		829.175	855.734	883.144	911.433	29.365.911
2 Cumulative Investment Replacements		26.715.600	27.571.335	28.454.479	29.365.911	
3 New Customers - Avg Request for Service		1.894	1.894	1.894	1.894	
4 Annual Capital Additions - New Customers		478.796	496.588	513.969	531.958	10.126.227
5 Cumulative Capital Additions - New Customers		8.583.731	9.080.200	9.594.269	10.126.227	
6 Depreciation of OC and Capital Additions		12	13	14	15	
	1981	12	13	14	15	
	1982	0	0	0	0	
	1983	0	0	0	0	
	1984	18.190	0	0	0	
	1985	18.795	18.795	0	0	
	1986	19.420	19.420	19.420	0	
	1987	20.067	20.067	20.067	20.067	
	1988	20.734	20.734	20.734	20.734	
	1989	21.424	21.424	21.424	21.424	
	1990	22.137	22.137	22.137	22.137	
	1991	22.874	22.874	22.874	22.874	
	1992	23.635	23.635	23.635	23.635	
	1993	24.422	24.422	24.422	24.422	
	1994	25.235	25.235	25.235	25.235	
	1995	26.075	26.075	26.075	26.075	
	1996	26.943	26.943	26.943	26.943	
	1997	27.840	27.840	27.840	27.840	
	1998	28.768	28.768	28.768	28.768	
	1999	29.728	29.728	29.728	29.728	
	2000	30.721	30.721	30.721	30.721	
	2001	31.748	31.748	31.748	31.748	
	2002	32.810	32.810	32.810	32.810	
	2003	33.908	33.908	33.908	33.908	
	2004	35.043	35.043	35.043	35.043	
	2005	36.216	36.216	36.216	36.216	
	2006	37.428	37.428	37.428	37.428	
	2007	38.681	38.681	38.681	38.681	
	2008	39.976	39.976	39.976	39.976	
	2009	41.315	41.315	41.315	41.315	
	2010		42.699	42.699	42.699	
	2011			44.130	44.130	
	Annual Depr [3.902.370]	730.750	750.336	775.201	800.888	21.979.779
	Cumm Depr	19.653.353	20.403.689	21.178.891	21.979.779	
Net Book Value		15.615.959	16.247.945	16.869.857	17.512.360	17.512.360
Cost						
NBV Cost						
Pure rate						
	CA Depr	730.750	750.223	775.167	800.853	
	Cum CA Depr	1.438.176	1.481.061	1.525.510	1.576.060	

For depreciation only Workpapers

CALCUALTION OF NET BOOK VALUE AS OF YEAR END 1996-2001-2011

Distribution Plant

Street Lighting and Signal Systems	Inputs	1981 Service Life 27	1982 Depr Rate 3.70%	1983 Escalation 3.70%	1984 Avg Age 8	1985 1981 Avg Remaining Life 19	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997 Escalation 3.70%
1 Original Cost 1981- Capital Additions		5,816,540	222,967	231,514	240,389	249,604	259,172	269,107	279,422	290,131	301,255	312,804	324,794	337,245	350,173	363,596	377,534	388,238
2 Cumulative Investment			6,039,197	6,271,011	6,511,400	6,761,003	7,020,175	7,289,282	7,568,704	7,858,835	8,160,091	8,472,895	8,797,689	9,134,934	9,485,107	9,848,703	10,226,238	10,614,457
3 Depreciation of OC and Capital Additions																		
	1981		215,427	215,427	215,427	215,427	215,427	215,427	215,427	215,427	215,427	215,427	215,427	215,427	215,427	215,427	215,427	215,427
	1982		8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258	8,258
	1983			8,575	8,575	8,575	8,575	8,575	8,575	8,575	8,575	8,575	8,575	8,575	8,575	8,575	8,575	8,575
	1984				8,903	8,903	8,903	8,903	8,903	8,903	8,903	8,903	8,903	8,903	8,903	8,903	8,903	8,903
	1985					9,245	9,245	9,245	9,245	9,245	9,245	9,245	9,245	9,245	9,245	9,245	9,245	9,245
	1986						9,599	9,599	9,599	9,599	9,599	9,599	9,599	9,599	9,599	9,599	9,599	9,599
	1987							9,967	9,967	9,967	9,967	9,967	9,967	9,967	9,967	9,967	9,967	9,967
	1988								10,349	10,349	10,349	10,349	10,349	10,349	10,349	10,349	10,349	10,349
	1989									10,746	10,746	10,746	10,746	10,746	10,746	10,746	10,746	10,746
	1990										11,158	11,158	11,158	11,158	11,158	11,158	11,158	11,158
	1991											11,585	11,585	11,585	11,585	11,585	11,585	11,585
	1992												12,029	12,029	12,029	12,029	12,029	12,029
	1993													12,491	12,491	12,491	12,491	12,491
	1994														12,969	12,969	12,969	12,969
	1995															13,467	13,467	13,467
	1996																13,983	13,983
	1997																	14,378
	1998																	
	1999																	
	2000																	
	2001																	
	2002																	
	2003																	
	2004																	
	2005																	
	2006																	
	2007																	
	2008																	
	2009																	
	2010																	
	2011																	
Annual Depr	1,723,416	0	223,685	232,260	241,163	250,408	260,006	269,973	280,322	291,068	302,226	313,811	325,840	338,331	351,300	364,767	378,750	393,128
Cumm Depr		1,723,416	1,947,101	2,179,361	2,420,524	2,670,931	2,930,938	3,200,911	3,481,234	3,772,302	4,074,527	4,388,338	4,714,179	5,052,510	5,403,810	5,768,577	6,147,326	6,540,454
Net Book Value		4,093,124	4,092,396	4,091,650	4,090,876	4,090,072	4,089,238	4,088,371	4,087,471	4,086,537	4,085,566	4,084,559	4,083,513	4,082,427	4,081,299	4,080,128	4,078,912	4,074,002
CA Depr		0	8,258	16,833	25,736	34,980	44,579	54,546	64,895	75,641	86,799	98,384	110,413	122,904	135,873	149,340	163,323	177,701
Cum CA Depr		0	8,258	25,091	42,569	60,716	79,560	99,126	119,412	140,536	162,440	185,183	208,797	233,317	258,777	285,213	312,662	341,024

Distribution Plant

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Street Lighting and Signal Systems										
Inputs										
1 Annual Cost (1998 Capital Additions	107 956	418 254	434 132	450 613	467 719	485 475	503 903	523 035	542 891	563 501
2 Cumulative Investment	11 017 413	11 435 667	11 869 798	12 320 411	12 788 130	13 273 606	13 777 511	14 300 546	14 843 437	15 406 938
3 Depreciation at 6% and Capital Additions										
1981	215 427	215 427	215 427	215 427	0	0	0	0	0	0
1982	8 258	8 258	8 258	8 258	8 258	8 258	8 258	8 258	8 258	8 258
1983	8 573	8 573	8 573	8 573	8 573	8 573	8 573	8 573	8 573	8 573
1984	8 903	8 903	8 903	8 903	8 903	8 903	8 903	8 903	8 903	8 903
1985	9 245	9 245	9 245	9 245	9 245	9 245	9 245	9 245	9 245	9 245
1986	9 599	9 599	9 599	9 599	9 599	9 599	9 599	9 599	9 599	9 599
1987	9 967	9 967	9 967	9 967	9 967	9 967	9 967	9 967	9 967	9 967
1988	10 349	10 349	10 349	10 349	10 349	10 349	10 349	10 349	10 349	10 349
1989	10 746	10 746	10 746	10 746	10 746	10 746	10 746	10 746	10 746	10 746
1990	11 158	11 158	11 158	11 158	11 158	11 158	11 158	11 158	11 158	11 158
1991	11 585	11 585	11 585	11 585	11 585	11 585	11 585	11 585	11 585	11 585
1992	12 029	12 029	12 029	12 029	12 029	12 029	12 029	12 029	12 029	12 029
1993	12 491	12 491	12 491	12 491	12 491	12 491	12 491	12 491	12 491	12 491
1994	12 969	12 969	12 969	12 969	12 969	12 969	12 969	12 969	12 969	12 969
1995	13 467	13 467	13 467	13 467	13 467	13 467	13 467	13 467	13 467	13 467
1996	13 983	13 983	13 983	13 983	13 983	13 983	13 983	13 983	13 983	13 983
1997	14 378	14 378	14 378	14 378	14 378	14 378	14 378	14 378	14 378	14 378
1998	14 924	14 924	14 924	14 924	14 924	14 924	14 924	14 924	14 924	14 924
1999		15 491	15 491	15 491	15 491	15 491	15 491	15 491	15 491	15 491
2000			16 079	16 079	16 079	16 079	16 079	16 079	16 079	16 079
2001				16 689	16 689	16 689	16 689	16 689	16 689	16 689
2002					17 323	17 323	17 323	17 323	17 323	17 323
2003						17 981	17 981	17 981	17 981	17 981
2004							18 663	18 663	18 663	18 663
2005								19 372	19 372	19 372
2006									20 107	20 107
2007										20 870
2008										
2009										
2010										
2011										
Annual Depr [1.721 416]	408 052	423 543	439 622	456 312	258 207	276 188	294 851	314 223	334 330	355 200
Cumm Depr	6 948 307	7 372 050	7 811 672	8 267 984	8 526 191	8 802 379	9 097 230	9 411 453	9 745 783	10 100 983
Net Book Value	4 068 906	4 063 617	4 058 126	4 052 427	4 261 939	4 471 227	4 680 281	4 889 093	5 097 654	5 305 955
CA Depr	197 625	209 316	224 195	240 884	258 207	276 188	294 851	314 223	334 330	355 200
Cumm CA Depr	370 326	400 741	432 311	463 068	499 092	534 195	571 039	609 074	648 533	689 530

Distribution Plant

Street Lighting and Signal Systems

		2008	2009	2010	2011	Cumulative
1 Unigrand Cost 1981 Capital Additions		783 893	607 097	620 145	651 067	17,863,140
2 Cumulative Investment		15 991 831	16 598 929	17 229 073	17 803 140	
3 Experiments of OC and Capital Additions						
	1981	0	0	0	0	
	1982	8 278	0	0	0	
	1983	8 573	8 573	0	0	
	1984	8 903	8 903	8 903	0	
	1985	9 245	9 245	9 245	9 245	
	1986	9 599	9 599	9 599	9 599	
	1987	9 967	9 967	9 967	9 967	
	1988	10 349	10 349	10 349	10 349	
	1989	10 746	10 746	10 746	10 746	
	1990	11 158	11 158	11 158	11 158	
	1991	11 585	11 585	11 585	11 585	
	1992	12 029	12 029	12 029	12 029	
	1993	12 491	12 491	12 491	12 491	
	1994	12 969	12 969	12 969	12 969	
	1995	13 467	13 467	13 467	13 467	
	1996	13 983	13 981	13 983	13 983	
	1997	14 378	14 378	14 378	14 378	
	1998	14 921	14 924	14 924	14 924	
	1999	15 491	15 491	15 491	15 491	
	2000	16 079	16 079	16 079	16 079	
	2001	16 689	16 689	16 689	16 689	
	2002	17 323	17 323	17 323	17 323	
	2003	17 981	17 981	17 981	17 981	
	2004	18 663	18 663	18 663	18 663	
	2005	19 372	19 372	19 372	19 372	
	2006	20 107	20 107	20 107	20 107	
	2007	20 870	20 870	20 870	20 870	
	2008	21 663	21 663	21 663	21 663	
	2009		22 465	22 465	22 465	
	2010			23 339	23 339	
	2011				24 225	
	Annual Depr [3.721.486]	376 863	391 090	405 854	421 176	11,695,966
	Cumm Depr	10 477 816	10 868 936	11 274 791	11 695 966	
Net Book Valu		5 514 015	5 729 992	5 954 283	6 107 174	6 107 174
	CA Depr	376 863	391 090	405 854	421 176	
	Cum CA Depr	732 063	767 953	796 944	827 030	

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CALCUALTION OF NET BOOK VALUE AS OF YEAR END 1996-2001-2011

Martin Substation

Structures and Improvements	Input	1981 Service Life 50	1982 Depr Rate 2.00%	1983 Escalation 3.50%	1984 Avg Age 23	1985 1981 Avg Remaining Life 23	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997 Escalation 2.50%
1 Original Cost 1981 Capital Additions		364 853	7,532	7,686	7,917	8,009	8,175	8,344	8,517	8,693	8,873	9,057	9,244	9,436	9,631	9,830	10,034	10,243
2 Cumulative Investment			372,385	379,872	316,919	394,928	403,103	411,448	419,965	428,658	437,531	446,588	455,832	465,268	474,899	484,730	494,764	504,906
																		1
3 Depreciation of 98 and Capital Additions																		1
	1981		7,277	7,277	7,277	7,277	7,277	7,277	7,277	7,277	7,277	7,277	7,277	7,277	7,277	7,277	7,277	7,277
	1982		151	151	151	151	151	151	151	151	151	151	151	151	151	151	151	151
	1983			154	154	154	154	154	154	154	154	154	154	154	154	154	154	154
	1984				157	157	157	157	157	157	157	157	157	157	157	157	157	157
	1985				160	160	160	160	160	160	160	160	160	160	160	160	160	160
	1986					163	163	163	163	163	163	163	163	163	163	163	163	163
	1987						167	167	167	167	167	167	167	167	167	167	167	167
	1988							170	170	170	170	170	170	170	170	170	170	170
	1989								174	174	174	174	174	174	174	174	174	174
	1990									177	177	177	177	177	177	177	177	177
	1991										181	181	181	181	181	181	181	181
	1992											185	185	185	185	185	185	185
	1993												189	189	189	189	189	189
	1994													193	193	193	193	193
	1995														197	197	197	197
	1996																201	201
	1997																	205
	1998																	
	1999																	
	2000																	
	2001																	
	2002																	
	2003																	
	2004																	
	2005																	
	2006																	
	2007																	
	2008																	
	2009																	
	2010																	
	2011																	
Accum Depr	196 481	0	7,428	7,581	7,738	7,899	8,062	8,229	8,399	8,573	8,751	8,932	9,117	9,305	9,496	9,695	9,893	10,099
Comm Depr		196,481	203,909	211,490	219,229	227,127	235,189	243,418	251,817	260,391	269,141	278,073	287,190	296,495	305,991	315,686	325,579	335,682
Net Book Value		167,372	167,476	167,582	167,691	167,801	167,914	168,030	168,147	168 267	168,390	168 515	168,643	168,773	168 906	169,042	169,181	169,324
CA Depr		0	151	301	461	622	785	952	1,122	1,296	1,474	1,655	1,840	2,028	2,221	2,418	2,618	2,823
Cum CA Depr		0	151	455	766	1,083	1,407	1,737	2,074	2,418	2,770	3,128	3,494	3,868	4,249	4,638	5,036	5,439

Martin Substation

Structures and Improvements

Depn

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
1 Original Cost 1981/Capital Additions	10 351	10.561	10.779	11.008	11.226	11.456	11.691	11.930	12.175	12.425
2 Cumulative Investment	515 257	525.870	536.599	547.599	558 825	570.281	581.972	593.902	606.077	618.502
	2	3	4	5	6	7	8	9	10	11
3 Depreciation of OC and Capital Additions	2	3	4	5	6	7	8	9	10	11
1981	7.277	7.277	7.277	7.277	0	0	0	0	0	0
1982	151	151	151	151	151	151	151	151	151	151
1983	154	154	154	154	154	154	154	154	154	154
1984	157	157	157	157	157	157	157	157	157	157
1985	160	160	160	160	160	160	160	160	160	160
1986	163	163	163	163	163	163	163	163	163	163
1987	167	167	167	167	167	167	167	167	167	167
1988	170	170	170	170	170	170	170	170	170	170
1989	174	174	174	174	174	174	174	174	174	174
1990	177	177	177	177	177	177	177	177	177	177
1991	181	181	181	181	181	181	181	181	181	181
1992	185	185	185	185	185	185	185	185	185	185
1993	189	189	189	189	189	189	189	189	189	189
1994	193	193	193	193	193	193	193	193	193	193
1995	197	197	197	197	197	197	197	197	197	197
1996	201	201	201	201	201	201	201	201	201	201
1997	203	203	203	203	203	203	203	203	203	203
1998	207	207	207	207	207	207	207	207	207	207
1999		211	211	211	211	211	211	211	211	211
2000			216	216	216	216	216	216	216	216
2001				220	220	220	220	220	220	220
2002					225	225	225	225	225	225
2003						229	229	229	229	229
2004							234	234	234	234
2005								239	239	239
2006									243	243
2007										248
2008										
2009										
2010										
2011										
Annual Depr [196.191]	10 107	10.319	10.726	10.957	3.905	4.126	4.370	4.640	4.854	5.104
Cumm Depr	135.989	156.308	167.744	178.701	182.107	186.242	190.613	195.223	200.077	205.181
Net Book Value	169.268	169.311	169.351	169.398	176.718	184.038	191.359	198.679	206.000	213.320
CA Depr	3 028	3.239	3.455	3 675	3 899	4.129	4.362	4 601	4 844	5.093
Cum CA Depr	5 819	6.267	6.694	7.130	7.571	8.028	8.491	8.963	9 445	9.937

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Martin Substation

Structures and Improvements [Depr:]	2008	2009	2010	2011	Cumulative
1 Original Cost 1981 Capital Additions	12 679	12 939	13 201	13 475	670 800
2 Cumulative Investment	631 841	644 120	657 324	670 800	
3 Depreciation on OC and Capital Additions	12	13	14	15	
1981	0	0	0	0	
1982	151	0	0	0	
1983	154	154	0	0	
1984	157	157	157	0	
1985	160	160	160	160	
1986	164	164	164	163	
1987	167	167	167	167	
1988	170	170	170	170	
1989	174	174	174	174	
1990	177	177	177	177	
1991	181	181	181	181	
1992	185	185	185	185	
1993	189	189	189	189	
1994	192	192	192	192	
1995	197	197	197	197	
1996	201	201	201	201	
1997	203	203	203	203	
1998	207	207	207	207	
1999	211	211	211	211	
2000	216	216	216	216	
2001	220	220	220	220	
2002	225	225	225	225	
2003	229	229	229	229	
2004	234	234	234	234	
2005	239	239	239	239	
2006	243	243	243	243	
2007	248	248	248	248	
2008	254	254	254	253	
2009		259	259	259	
2010			264	264	
2011				270	
Annual Depr [196 484]	5 159	5 466	5 579	5 691	427 279
Cumm Depr	410 540	416 007	421 587	427 279	
Net Book Value	220 631	228 113	235 738	243 521	243 521
CA Depr	5 317	5 455	5 565	5 678	
Cumm CA Depr	10 140	10 601	11 020	11 243	

CALCULATION OF NET BOOK VALUE AS OF YEAR END 1996 2001 2011

Martin Substation

Station Equipment	Inputs	1981 Service Life 22	1982 Depr Rate 4.55%	1983 Escalation 3.50%	1984 Avg Age 21	1985 1981 Avg Remaining Life 1	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997 Escalation 3.50%
1 Original Cost 1981 Capital Additions		3 014 485	141 818	148 490	155 475	162 790	170 448	178 467	186 863	195 654	204 859	214 497	224 588	235 154	246 217	257 800	269 928	278 896
2 Cumulative Investment			3 156 303	3 304 793	3 460 268	3 623 058	3 793 506	3 971 973	4 158 837	4 354 491	4 559 350	4 773 847	4 998 435	5 233 588	5 479 805	5 737 605	6 007 533	6 287 429
3 Depreciation of OC and Capital Additions-																		
	1981		137 022	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	1982		6 446	6 446	6 446	6 446	6 446	6 446	6 446	6 446	6 446	6 446	6 446	6 446	6 446	6 446	6 446	6 446
	1983			6 750	6 750	6 750	6 750	6 750	6 750	6 750	6 750	6 750	6 750	6 750	6 750	6 750	6 750	6 750
	1984				7 067	7 067	7 067	7 067	7 067	7 067	7 067	7 067	7 067	7 067	7 067	7 067	7 067	7 067
	1985					7 400	7 400	7 400	7 400	7 400	7 400	7 400	7 400	7 400	7 400	7 400	7 400	7 400
	1986						7 748	7 748	7 748	7 748	7 748	7 748	7 748	7 748	7 748	7 748	7 748	7 748
	1987							8 112	8 112	8 112	8 112	8 112	8 112	8 112	8 112	8 112	8 112	8 112
	1988								8 491	8 491	8 491	8 491	8 491	8 491	8 491	8 491	8 491	8 491
	1989									8 893	8 893	8 893	8 893	8 893	8 893	8 893	8 893	8 893
	1990										9 312	9 312	9 312	9 312	9 312	9 312	9 312	9 312
	1991											9 750	9 750	9 750	9 750	9 750	9 750	9 750
	1992												10 209	10 209	10 209	10 209	10 209	10 209
	1993													10 689	10 689	10 689	10 689	10 689
	1994														11 192	11 192	11 192	11 192
	1995															11 710	11 710	11 710
	1996																12 269	12 269
	1997																	12 723
	1998																	
	1999																	
	2000																	
	2001																	
	2002																	
	2003																	
	2004																	
	2005																	
	2006																	
	2007																	
	2008																	
	2009																	
	2010																	
	2011																	
	Annual Depr [2,877,463]	0	143 468	14 196	20 263	27 662	35 410	43 522	52 096	60 909	70 221	79 971	90 180	100 868	112 060	123 778	136 048	148 730
	Cmun Depr	2 877 463	3 020 931	3 041 127	3 054 390	3 082 052	3 117 462	3 160 985	3 213 081	3 273 990	3 344 211	3 424 182	3 514 282	3 615 150	3 727 210	3 850 988	3 987 036	4 135 766
Net Book Value			137 022	135 372	270 665	105 878	541 005	676 044	810 989	995 816	1 080 581	1 215 219	1 349 345	1 481 153	1 618 638	1 752 595	1 886 647	2 020 497	2 151 623
	CA Depr		0	6 446	14 196	20 263	27 662	35 410	43 522	52 096	60 909	70 221	79 971	90 180	100 868	112 060	123 778	136 048	148 730
	Cum CA Depr		0	6 446	19 642	39 159	47 925	63 072	78 932	95 538	112 925	131 131	150 192	170 151	191 018	212 928	235 838	259 826	284 816

Martin Substation

Station Equipment

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Original Cost 1998 Capital Additions	292.917	306.585	320.869	335.819	351.465	367.840	384.978	402.915	421.687	441.334
Cumulative Investment	6 580.166	6 886.952	7.207.821	7.543.640	7.895.105	8.262.945	8 647.923	9.050.838	9 472.525	9.913.858
Depreciation of OC and Capital Additions										
1961	0	0	0	0	0	0	0	0	0	0
1962	6.416	6 416	6 416	6 416	6 416	6 416	6 416	0	0	0
1963	6.750	6.750	6.750	6 750	6.750	6.750	6.750	6.750	0	0
1964	7.067	7.067	7.067	7.067	7.067	7.067	7.067	7.067	7.067	0
1965	7.400	7.400	7.400	7.400	7.400	7.400	7.400	7.400	7.400	7.400
1966	7.748	7.748	7.748	7.748	7.748	7.748	7.748	7.748	7.748	7.748
1967	8.112	8.112	8.112	8.112	8.112	8.112	8.112	8.112	8.112	8.112
1968	8.494	8.494	8.494	8.494	8.494	8.494	8.494	8.494	8.494	8.494
1969	8.893	8.893	8.893	8.893	8.893	8.893	8.893	8.893	8.893	8.893
1970	9.312	9.312	9.312	9.312	9.312	9.312	9.312	9.312	9.312	9.312
1971	9.750	9.750	9.750	9.750	9.750	9.750	9.750	9.750	9.750	9.750
1972	10.209	10.209	10.209	10.209	10.209	10.209	10.209	10.209	10.209	10.209
1973	10.689	10.689	10.689	10.689	10.689	10.689	10.689	10.689	10.689	10.689
1974	11.192	11.192	11.192	11.192	11.192	11.192	11.192	11.192	11.192	11.192
1975	11.718	11.718	11.718	11.718	11.718	11.718	11.718	11.718	11.718	11.718
1976	12.269	12.269	12.269	12.269	12.269	12.269	12.269	12.269	12.269	12.269
1977	12.723	12.723	12.723	12.723	12.723	12.723	12.723	12.723	12.723	12.723
1978	13.315	13.315	13.315	13.315	13.315	13.315	13.315	13.315	13.315	13.315
1979		13.936	13.936	13.936	13.936	13.936	13.936	13.936	13.936	13.936
2000			14.585	14.585	14.585	14.585	14.585	14.585	14.585	14.585
2001				15.264	15.264	15.264	15.264	15.264	15.264	15.264
2002					15.976	15.976	15.976	15.976	15.976	15.976
2003						16.720	16.720	16.720	16.720	16.720
2004							17.499	17.499	17.499	17.499
2005								18.314	18.314	18.314
2006									19.168	19.168
2007										20.061
2008										
2009										
2010										
2011										
Annual Depr [2.877463]	162.086	176.021	190.606	205.871	221.846	238.566	256.065	267.933	280.351	293.345
Cumm Depr	4.297.892	4.473.913	4.664.519	4 870.390	5.092.236	5.330.802	5.586.868	5.854.801	6 135.153	6.428.498
Net Book Value	2.282.475	2.413.039	2.543.302	2.673 250	2.802.869	2.932.143	3.061.056	3.196.037	3.337.372	3.485.361
CA Depr	162.086	176.021	190.606	205.871	221.846	238.566	256.065	267.933	280.351	293.345
Cumm CA Depr	310.856	338.107	366 627	396.477	427.717	460.413	494.632	523.999	548.285	573.696

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Martin Substation

Station Equipment	2008	2009	2010	2011	Cumulative
[... basis ...]					
1 Original Cost 1981/ Capital Additions	461,806	461,416	505,939	529,511	11,891,619
2 Cumulative Investment	10,375,754	10,859,170	11,365,108	11,894,619	
3 Depreciation of OC and Capital Additions					
1981	0	0	0	0	
1982	0	0	0	0	
1983	0	0	0	0	
1984	0	0	0	0	
1985	0	0	0	0	
1986	7,748	0	0	0	
1987	8,112	8,112	0	0	
1988	8,494	8,494	8,494	0	
1989	8,893	8,893	8,893	8,893	
1990	9,312	9,312	9,312	9,312	
1991	9,750	9,750	9,750	9,750	
1992	10,209	10,209	10,209	10,209	
1993	10,689	10,689	10,689	10,689	
1994	11,192	11,192	11,192	11,192	
1995	11,718	11,718	11,718	11,718	
1996	12,269	12,269	12,269	12,269	
1997	12,723	12,723	12,723	12,723	
1998	13,315	13,315	13,315	13,315	
1999	13,936	13,936	13,936	13,936	
2000	14,585	14,585	14,585	14,585	
2001	15,264	15,264	15,264	15,264	
2002	15,976	15,976	15,976	15,976	
2003	16,720	16,720	16,720	16,720	
2004	17,499	17,499	17,499	17,499	
2005	18,314	18,314	18,314	18,314	
2006	19,168	19,168	19,168	19,168	
2007	20,061	20,061	20,061	20,061	
2008	20,995	20,995	20,995	20,995	
2009		21,973	21,973	21,973	
2010			22,997	22,997	
2011				24,069	
Annual Depr [2.877464]	306,941	321,167	336,052	351,626	7,744,283
Cmun Depr	6,735,438	7,056,605	7,392,656	7,744,283	
Net Book Value	3,640,316	3,802,565	3,972,452	4,150,336	4,150,336
CA Depr	306,941	321,167	336,052	351,626	
Cmu CA Depr	600,286	628,107	657,230	687,678	

CALCUALTION OF NET BOOK VALUE AS OF YEAR END 1996 2001-2011

Martin Sobastian

Structures Improvement & Equipment	1981 Service Life	1982 Depr Rate	1981 Escalation	1983 Avg Age	1982 1981 Avg Remaining Life	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997 Escalation
Inputs	50	2.00%	3.50%	27	23												2.50%
1 Original Cost 1981 Capital Additions	5,232	104	111	133	115	118	120	122	125	128	130	133	136	138	141	144	146
2 Cumulative Depreciation		5,340	5,451	5,561	5,679	5,796	5,916	6,039	6,164	6,291	6,422	6,555	6,690	6,829	6,970	7,114	7,260
3 Depreciation of OC and Capital Additions																	
1981		105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105
1982		2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
1983			2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
1984				2	2	2	2	2	2	2	2	2	2	2	2	2	2
1985					2	2	2	2	2	2	2	2	2	2	2	2	2
1986						2	2	2	2	2	2	2	2	2	2	2	2
1987							2	2	2	2	2	2	2	2	2	2	2
1988								2	2	2	2	2	2	2	2	2	2
1989									3	3	3	3	3	3	3	3	3
1990										3	3	3	3	3	3	3	3
1991											3	3	3	3	3	3	3
1992												3	3	3	3	3	3
1993													3	3	3	3	3
1994														3	3	3	3
1995															3	3	3
1996																3	3
1997																	3
1998																	
1999																	
2000																	
2001																	
2002																	
2003																	
2004																	
2005																	
2006																	
2007																	
2008																	
2009																	
2010																	
2011																	
Annual Depr [5,232]	0	107	109	111	114	116	118	121	123	126	128	131	134	137	139	142	145
Cumm Depr	732	839	948	1,059	1,173	1,289	1,407	1,528	1,651	1,777	1,905	2,036	2,170	2,307	2,446	2,588	2,734
Net Book Value	4,500	4,501	4,503	4,505	4,506	4,508	4,509	4,511	4,513	4,515	4,516	4,518	4,520	4,522	4,524	4,526	4,527
4 A Depr	0	2	4	7	9	11	14	16	19	21	24	26	29	32	35	38	41
Cum CA Depr	0	2	7	11	16	20	25	30	35	40	45	50	56	61	67	72	78

Martin Substation

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Structures Improvement & Equipment [Depn]										
1 Original Cost 1981 Capital Additions	119	152	155	158	161	165	168	172	175	179
2 Cumulative Investment	7,409	7,561	7,716	7,874	8,036	8,200	8,368	8,540	8,715	8,894
3 Depreciation of OC and Capital Additions-										
1981	105	105	105	105	0	0	0	0	0	0
1982	2	2	2	2	2	2	2	0	0	0
1983	2	2	2	2	2	2	2	2	0	0
1984	2	2	2	2	2	2	2	2	2	0
1985	2	2	2	2	2	2	2	2	2	2
1986	2	2	2	2	2	2	2	2	2	2
1987	2	2	2	2	2	2	2	2	2	2
1988	2	2	2	2	2	2	2	2	2	2
1989	3	3	3	3	3	3	3	3	3	3
1990	3	3	3	3	3	3	3	3	3	3
1991	3	3	3	3	3	3	3	3	3	3
1992	3	3	3	3	3	3	3	3	3	3
1993	3	3	3	3	3	3	3	3	3	3
1994	3	3	3	3	3	3	3	3	3	3
1995	3	3	3	3	3	3	3	3	3	3
1996	3	3	3	3	3	3	3	3	3	3
1997	3	3	3	3	3	3	3	3	3	3
1998	3	3	3	3	3	3	3	3	3	3
1999		3	3	3	3	3	3	3	3	3
2000			3	3	3	3	3	3	3	3
2001				3	3	3	3	3	3	3
2002					3	3	3	3	3	3
2003						3	3	3	3	3
2004							3	3	3	3
2005								3	3	3
2006									4	4
2007										4
2008										
2009										
2010										
2011										
Annual Depn [732]	118	151	154	157	56	59	63	64	65	67
Cum Depr	2,802	3,033	3,187	3,345	3,401	3,460	3,523	3,587	3,652	3,719
Net Book Value	4,527	4,528	4,529	4,529	4,635	4,740	4,845	4,953	5,063	5,175
CA Depn	44	47	50	53	56	59	63	64	65	67
Cum CA Depr	81	90	96	103	109	115	122	127	129	132

CALCUALTION OF NET BOOK VALUE AS OF YEAR END 1996 2001-2011

Martin Substation

Investment Improvement & Equipment		1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
		Service Life	Depr Rate	Escalation	Avg Age	1981 Avg Remaining Life												Escalation
	Inputs	50	2.00%	3.50%	27	23												3.50%
1 Original Cost 1981 Capital Additions		3,232	108	111	113	115	118	120	122	123	126	130	132	136	138	141	144	146
2 Cumulative Investment			3,340	3,451	3,564	3,679	3,796	3,916	4,039	4,161	4,291	4,422	4,555	4,690	4,829	4,970	5,114	5,260
3 Depreciation of 1981 Capital Additions																		
	1981		105	105	105	105	105	105	105	105	105	105	105	105	105	105	105	105
	1982		2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	1983			2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
	1984				2	2	2	2	2	2	2	2	2	2	2	2	2	2
	1985					2	2	2	2	2	2	2	2	2	2	2	2	2
	1986						2	2	2	2	2	2	2	2	2	2	2	2
	1987							2	2	2	2	2	2	2	2	2	2	2
	1988								2	2	2	2	2	2	2	2	2	2
	1989									2	2	2	2	2	2	2	2	2
	1990										3	3	3	3	3	3	3	3
	1991											3	3	3	3	3	3	3
	1992												3	3	3	3	3	3
	1993													3	3	3	3	3
	1994														3	3	3	3
	1995															3	3	3
	1996																2	3
	1997																	3
	1998																	
	1999																	
	2000																	
	2001																	
	2002																	
	2003																	
	2004																	
	2005																	
	2006																	
	2007																	
	2008																	
	2009																	
	2010																	
	2011																	
	Annual Depr	(3,232)	0	107	109	111	114	116	118	121	123	126	128	131	134	137	139	142	145
	Cumm Depr		732	839	948	1,059	1,173	1,289	1,407	1,528	1,651	1,777	1,905	2,036	2,170	2,307	2,446	2,588	2,734
Net Book Value			4,500	4,501	4,503	4,505	4,506	4,508	4,509	4,511	4,512	4,513	4,516	4,518	4,520	4,522	4,524	4,526	4,527
	CA Depr		0	2	4	7	9	11	14	16	19	21	24	26	29	32	35	38	41
	Cum CA Depr		0	2	7	11	16	20	25	30	35	40	45	50	56	61	67	72	78

Martin Substation

Structures Improvement & Equipment [Inputs]

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
1 Original Cost 1981/ Capital Additions	149	152	155	158	161	165	168	172	175	179
2 Cumulative Investment	7 409	7,561	7,716	7 874	8,036	8 200	8,368	8 540	8,715	8,894
3 Depreciation of OC and Capital Additions										
1981	105	105	105	105	0	0	0	0	0	0
1982	2	2	2	2	2	2	2	0	0	0
1983	2	2	2	2	2	2	2	2	0	0
1984	2	2	2	2	2	2	2	2	2	0
1985	2	2	2	2	2	2	2	2	2	2
1986	2	2	2	2	2	2	2	2	2	2
1987	2	2	2	2	2	2	2	2	2	2
1988	2	2	2	2	2	2	2	2	2	2
1989	3	3	3	3	3	3	3	3	3	3
1990	3	3	3	3	3	3	3	3	3	3
1991	3	3	3	3	3	3	3	3	3	3
1992	3	3	3	3	3	3	3	3	3	3
1993	3	3	3	3	3	3	3	3	3	3
1994	3	3	3	3	3	3	3	3	3	3
1995	3	3	3	3	3	3	3	3	3	3
1996	3	3	3	3	3	3	3	3	3	3
1997	3	3	3	3	3	3	3	3	3	3
1998	3	3	3	3	3	3	3	3	3	3
1999		3	3	3	3	3	3	3	3	3
2000			3	3	3	3	3	3	3	3
2001				3	3	3	3	3	3	3
2002					3	3	3	3	3	3
2003						3	3	3	3	3
2004							3	3	3	3
2005								3	3	3
2006									4	4
2007										4
2008										
2009										
2010										
2011										
Annual Depr [2.25%]	148	151	154	157	56	59	63	64	65	67
Cmun Depr	2,882	3,033	3,187	3 345	3,401	3,460	3,523	3,587	3,652	3,719
Net Book Value	4 527	4,528	4,529	4 529	4,635	4,740	4,845	4,953	5,063	5,175
CA Depr	44	47	50	53	56	59	63	64	65	67
Cum CA Depr	81	90	96	103	109	115	122	127	129	132

Martin Substation

	2008	2009	2010	2011	Cumulative
Structures Improvement & Equipment [Regrds]					
1 Unrecovered 1981 Capital Additions	162	186	190	191	9,646
2 Accumulated Investment	9,076	9,262	9,452	9,646	
3 Depreciation of UC and Capital Additions					
1981	0	0	0	0	
1982	0	0	0	0	
1983	0	0	0	0	
1984	0	0	0	0	
1985	0	0	0	0	
1986	2	0	0	0	
1987	2	2	0	0	
1988	2	2	2	0	
1989	3	3	3	3	
1990	3	3	3	3	
1991	3	3	3	3	
1992	3	3	3	3	
1993	3	3	3	3	
1994	3	3	3	3	
1995	3	3	3	3	
1996	3	3	3	3	
1997	3	3	3	3	
1998	3	3	3	3	
1999	3	3	3	3	
2000	3	3	3	3	
2001	3	3	3	3	
2002	3	3	3	3	
2003	3	3	3	3	
2004	3	3	3	3	
2005	3	3	3	3	
2006	4	4	4	4	
2007	4	4	4	4	
2008	4	4	4	4	
2009		4	4	4	
2010			4	4	
2011				4	
Annual Depr [723]	68	69	71	72	3,999
Cum Depr	3,787	3,856	3,927	3,999	
Net Book Value	5,289	5,406	5,525	5,647	5,647
CA Depr	68	69	71	72	
Cum CA Depr	135	137	140	143	

CALCULATION OF NET BOOK VALUE AS OF YEAR END 1996-2001-2011

Marlin Substation

Central Building Equipment		1981 Service Life	1982 Depr Rate	1982 Escalation	1983 Avg Age	1985 1981 Avg Remaining Life	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997 Escalation
	Inputs	28	3.57%	3.50%	11	17												2.50%
1 Original Cost 1981 Capital Additions		18 652	689	715	741	769	797	827	857	889	922	956	991	1,028	1,066	1,105	1,146	1,177
2 Cumulative Investment			19,341	20,056	20,798	21,567	22,364	23,190	24,048	24,937	25,858	26,814	27,805	28,833	29,899	31,004	32,150	33,327
3 Depreciation at OK and Capital Additions																		
	1981		666	666	666	666	666	666	666	666	666	666	666	666	666	666	666	666
	1982		25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
	1983			26	26	26	26	26	26	26	26	26	26	26	26	26	26	26
	1984				26	26	26	26	26	26	26	26	26	26	26	26	26	26
	1985					27	27	27	27	27	27	27	27	27	27	27	27	27
	1986						28	28	28	28	28	28	28	28	28	28	28	28
	1987							30	30	30	30	30	30	30	30	30	30	30
	1988								31	31	31	31	31	31	31	31	31	31
	1989									32	32	32	32	32	32	32	32	32
	1990										33	33	33	33	33	33	33	33
	1991											34	34	34	34	34	34	34
	1992												35	35	35	35	35	35
	1993													37	37	37	37	37
	1994														38	38	38	38
	1995															39	39	39
	1996																41	41
	1997																	21
	1998																	
	1999																	
	2000																	
	2001																	
	2002																	
	2003																	
	2004																	
	2005																	
	2006																	
	2007																	
	2008																	
	2009																	
	2010																	
	2011																	
	Annual Depr (7.420)	0	691	715	743	770	799	828	859	891	924	958	993	1,030	1,068	1,107	1,148	1,172
	Cumm Depr	7,178	8,019	8,735	9,478	10,248	11,047	11,875	12,734	13,624	14,548	15,506	16,499	17,528	18,596	19,704	20,852	22,023
Net Book Value		11,324	11,323	11,321	11,320	11,318	11,317	11,315	11,314	11,312	11,310	11,309	11,307	11,305	11,303	11,301	11,298	11,304
	CA Depr	0	25	50	77	104	133	162	193	224	257	292	327	364	402	441	482	506
	Cum CA Depr	0	25	75	127	181	237	295	355	417	482	549	618	691	765	843	923	988

Martha Substation

Central Building Equipment

(Inputs)

	1928	1999	2000	2001	2002	2003	2004	2005	2006	2007
1 Original Cost 1981 Capital Additions	1 220	1 265	1 311	1 359	1 409	1 460	1 514	1 569	1 627	1 686
2 Cumulative Investment	34 517	35 812	37 123	38 482	39 890	41 351	42 865	44 433	46 060	47 746
3 Depreciation of 1981 Capital Additions:										
1981	666	0	0	0	0	0	0	0	0	0
1982	25	25	25	25	25	25	25	25	25	25
1983	26	26	26	26	26	26	26	26	26	26
1984	26	26	26	26	26	26	26	26	26	26
1985	27	27	27	27	27	27	27	27	27	27
1986	28	28	28	28	28	28	28	28	28	28
1987	30	30	30	30	30	30	30	30	30	30
1988	31	31	31	31	31	31	31	31	31	31
1989	32	32	32	32	32	32	32	32	32	32
1990	33	33	33	33	33	33	33	33	33	33
1991	34	34	34	34	34	34	34	34	34	34
1992	35	35	35	35	35	35	35	35	35	35
1993	37	37	37	37	37	37	37	37	37	37
1994	38	38	38	38	38	38	38	38	38	38
1995	39	39	39	39	39	39	39	39	39	39
1996	41	41	41	41	41	41	41	41	41	41
1997	24	24	24	24	24	24	24	24	24	24
1998	24	24	24	24	24	24	24	24	24	24
1999		25	25	25	25	25	25	25	25	25
2000			26	26	26	26	26	26	26	26
2001				27	27	27	27	27	27	27
2002					28	28	28	28	28	28
2003						29	29	29	29	29
2004							30	30	30	30
2005								31	31	31
2006									33	33
2007										34
2008										
2009										
2010										
2011										
Annual Depr (1928)	1 196	555	562	609	637	666	696	728	760	794
Cumu Depr	21 220	21 775	24 336	24 965	25 602	26 268	26 964	27 692	28 453	29 247
Net Book Value	13 297	14 037	12 786	13 516	14 288	15 082	15 900	16 741	17 608	18 500
CA Depr	530	555	562	609	637	666	696	728	760	794
Cumu CA Depr	1 036	1 085	1 137	1 190	1 246	1 303	1 362	1 424	1 486	1 551

Martin Substation

Central Building Equipment	2008	2009	2010	2011	Accumulation
[Inputs]					
1 Original Cost 1983/ Capital Additions	1.746	1.812	1.878	1.917	55.131
2 Cumulative Investment	19.494	51.306	53.184	55.131	
3 Depreciation of OC and Capital Additions-					
1981	0	0	0	0	
1982	25	0	0	0	
1983	26	26	0	0	
1984	26	26	26	0	
1985	27	27	27	27	
1986	28	28	28	28	
1987	30	30	30	30	
1988	31	31	31	31	
1989	32	32	32	32	
1990	33	33	33	33	
1991	34	34	34	34	
1992	35	35	35	35	
1993	37	37	37	37	
1994	38	38	38	38	
1995	39	39	39	39	
1996	41	41	41	41	
1997	24	24	24	24	
1998	24	24	24	24	
1999	25	25	25	25	
2000	26	26	26	26	
2001	27	27	27	27	
2002	28	28	28	28	
2003	29	29	29	29	
2004	30	30	30	30	
2005	31	31	31	31	
2006	33	33	33	33	
2007	34	34	34	34	
2008	35	35	35	35	
2009		36	36	36	
2010			38	38	
2011				39	
Annual Depr [7.328]	829	811	853	865	32.631
Cumm Depr	10.075	10.916	11.769	12.634	
Net Book Value	19.419	20.390	21.415	22.497	22.497
CA Depr	829	811	853	865	
Cum CA Depr	1.623	1.670	1.693	1.758	

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Summary All Assets

	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
Original Cost																	
Total Capital Additions Per Year		$13,368,771	$13,847,481	$14,311,212	$14,859,727	$15,394,698	$15,949,907	$16,526,146	$17,124,238	$17,745,040	$18,389,443	$19,058,373	$19,752,795	$20,473,712	$21,222,167	$21,999,246	$22,653,230
Annual Depreciation		9,355,408	9,703,859	10,207,686	10,730,431	11,272,987	11,836,075	12,420,499	13,027,694	13,656,729	14,312,695	13,992,159	14,696,485	14,827,690	14,210,875	14,058,762	14,883,278
Consumable Depr		101,362,930	111,066,790	121,274,476	132,004,857	143,277,844	155,113,919	167,534,417	180,561,511	194,218,240	206,931,935	220,924,094	234,620,578	249,248,269	263,459,094	277,517,856	292,401,084
Net Book Value		192,769,213	192,911,864	201,979,160	204,133,725	212,299,466	216,412,299	220,518,946	224,616,020	228,701,401	234,310,149	240,046,363	245,702,673	254,348,635	258,360,028	266,300,521	274,070,523
Original Cost Depreciable Plant		$297,131,373	$310,978,854	$325,322,886	$340,182,612	$355,577,310	$371,527,217	$388,053,363	$405,177,601	$422,922,641	$441,312,084	$460,370,457	$480,122,252	$500,596,964	$521,819,131	$543,818,377	$566,471,607
Original Cost Including Land & Misc.																536,034,394	558,691,387
Depr %s		3.15%	3.12%	3.14%	3.15%	3.17%	3.19%	3.20%	3.22%	3.23%	2.89%	2.91%	2.94%	2.96%	2.72%	2.59%	2.63%
	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	1997
NBV of Items Not Included Above																8,924	9,147
Trans Plant SAI																2,043,896	2,043,896
Dist Plant Land																40,569	43,582
Submarine Cables																85,009	87,134
Installation Customer Premises																39,019	39,019
Mains Land																268,516,938	276,790,303
Net Book Including Above																	

Exhibit No. ___ (MJW-1)
Workpapers
Summary All Assets

	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
Original Cost				$641,750,618	$667,903,073	$700,019,179	$728,131,943	$757,279,533	$787,501,609	$818,839,404
Total Capital Additions Per Year	$23,479,581	$24,337,601	$25,227,934	26,152,455	32,116,107	28,112,766	29,147,588	30,222,076	31,337,795	32,496,171
				667,903,073	700,019,179	728,131,945	757,279,533	787,501,609	818,839,404	851,335,575
Annual Depreciation	14,270,912	15,158,669	16,080,963	14,765,740	15,434,363	15,919,753	16,916,243	17,943,824	19,010,086	20,116,323
Commonwealth Dept	306,671,996	321,830,665	337,911,627	357,657,368	368,091,731	384,011,483	400,927,729	418,871,353	437,881,639	457,998,163
Net Book Value	293,279,192	297,437,928	301,604,899	315,245,705	331,927,449	344,120,462	356,351,804	368,630,026	380,957,765	393,337,610
Original Cost Depreciable Plant	$369,951,188	$634,288,592	$639,316,526	$667,903,073	$700,019,179	$728,131,945	$757,279,533	$787,501,609	$818,839,404	$851,335,575
Original Cost Including Land & Misc.	592,174,113	606,515,231	641,746,906	670,137,864	702,257,076	730,370,741	759,523,225	789,751,499	821,095,493	853,594,168
Depr.%	2.42%	2.47%	2.51%	2.21%	2.20%	2.19%	2.23%	2.28%	2.32%	2.36%
	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007
NBV of Items Not Included Above										
Texas Plant SAI	9,376	9,610	9,850	10,097	10,349	10,608	10,873	11,145	11,423	11,709
Dirt Plant Used	2,043,896	2,043,896	2,043,896	2,043,896	2,043,896	2,043,896	2,043,896	2,043,896	2,043,896	2,043,896
Submarine Cables	42,623	43,688	44,781	45,900	47,048	48,224	49,429	50,665	51,932	53,230
Installation Customer Premises	89,313	91,545	93,834	96,180	98,584	101,049	103,575	106,165	108,819	111,539
Martin Fuel	38,019	38,019	38,019	38,019	38,019	38,019	38,019	38,019	38,019	38,019
Net Book Including Above	285,502,419	291,668,687	301,035,279	315,234,092	2,237,896	2,241,796	2,245,393	2,249,890	2,254,089	2,258,393
			Change in Misc		3,804	3,900	3,997	4,097	4,199	4,304

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	2010	2009	2010	2011	
Original Cost	$885,035,271	$885,035,271	$919,984,201	$956,230,706	Original Cost
Total Capital Additions Per Year	33,059,456	34,948,930	36,246,505	37,591,127	3.95%
	885,035,271	919,984,201	956,230,706	993,824,833	
Annual Depreciation	20,965,177	21,796,300	22,640,251	23,536,865	4.35%
Cummulative Depr	478,983,342	500,779,673	523,419,994	546,956,859	
Net Book Value	406,051,928	419,204,528	432,810,712	446,867,974	986,549,119
Original Cost Depreciable Plant	$885,035,271	$919,984,201	$956,230,706	$993,824,833	
Original Cost Including Land & Misc.	887,598,076	922,231,328	958,502,669	996,101,547	
Depr.%	2.37%	2.37%	2.37%	2.37%	
	2008	2009	2010	2011	
NBV of Items Not Included Above					
Texas Plant SAI	12,002	12,302	12,609	12,925	2.50%
Unit Plant Land	2,043,896	2,043,896	2,043,896	2,043,896	0.00%
Submarine Cables	54,561	55,925	57,323	58,756	2.50%
Installations Customer Premises	114,328	117,186	120,115	123,118	2.50%
Marion Land	38,019	38,019	38,019	38,019	0.00%
Net Book Including Above	2,262,805	2,267,327	2,271,963	2,276,714	
	4,412	4,522	4,635	4,751	Change in Misc

	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Original Cost	988,839,703	1,027,817,645	1,068,256,071	1,110,198,883	1,153,701,983	1,198,823,352	1,245,623,121	1,294,163,656	1,344,509,638	1,396,728,148
Total Capital Additions Per Year	38,987,942	40,438,426	41,942,811	43,503,100	45,121,369	46,799,769	48,540,535	50,345,981	52,218,510	54,160,612
	1,027,817,645	1,068,256,071	1,110,198,883	1,153,701,983	1,198,823,352	1,245,623,121	1,294,163,656	1,344,509,638	1,396,728,148	1,450,888,760
Annual Depreciation	24,539,067	25,605,723	26,718,744	27,880,146	29,092,030	30,356,593	31,676,123	33,053,010	34,489,747	35,988,936
Cummulative Depr	571,475,907	597,081,630	623,800,374	651,680,520	680,772,550	711,129,143	742,805,266	775,858,276	810,348,023	846,336,959
Net Book Value	456,341,739	471,174,441	486,398,508	502,021,463	518,050,802	534,493,978	551,358,390	568,651,362	586,380,125	604,551,801
Original Cost Depreciable Plant										
Original Cost Including Land & Misc.										
Depr.%										
NBV of Items Not Included Above										
Trans Plant S&I	13,248	13,579	13,918	14,266	14,623	14,989	15,363	15,747	16,141	16,545
Dist Plant Land	2,043,896	2,043,896	2,043,896	2,043,896	2,043,896	2,043,896	2,043,896	2,043,896	2,043,896	2,043,896
Submarine Cables	60,225	61,731	63,274	64,856	66,477	68,139	69,842	71,588	73,378	75,213
Installation Customer Premesis	126,196	129,351	132,585	135,900	139,297	142,780	146,349	150,008	153,758	157,602
Martin Land	38,019	38,019	38,019	38,019	38,019	38,019	38,019	38,019	38,019	38,019
Net Book Including Above	2,281,584	2,286,576	2,291,692	2,296,937	2,302,312	2,307,822	2,313,470	2,319,259	2,325,192	2,331,274
		4,992	5,117	5,244	5,376	5,510	5,648	5,789	5,934	6,082

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	2022	2023	2024	2025	2026	2027	2027	2029	2030	2031
Original Cost	1,450,888,760	1,507,063,629	1,565,327,592	1,625,758,261	1,688,436,132	1,753,444,688	1,820,870,513	1,890,803,404	1,963,336,491	2,038,566,364
Total Capital Additions Per Year	56,174,870	58,263,963	60,430,669	62,677,871	65,008,556	67,425,825	69,932,891	72,533,087	75,229,873	78,026,832
	1,507,063,629	1,565,327,592	1,625,758,261	1,688,436,132	1,753,444,688	1,820,870,513	1,890,803,404	1,963,336,491	2,038,566,364	2,116,593,196
Annual Depreciation	37,553,291	39,185,644	40,888,953	42,666,300	44,520,904	46,456,124	48,475,463	50,582,578	52,781,284	55,075,563
Cummulative Depr	883,890,250	923,075,894	963,964,847	1,006,631,147	1,051,152,051	1,097,608,175	1,146,083,637	1,196,666,215	1,249,447,499	1,304,523,063
Net Book Value	623,173,380	642,251,698	661,793,414	681,804,985	702,292,638	723,262,339	744,719,766	766,670,276	789,118,864	812,070,133
Original Cost Depreciable Plant										
Original Cost Including Land & Misc.										
Depr.%										
NBV of Items Not Included Above										
Trans Plant S&I	16,958	17,382	17,817	18,262	18,719	19,187	19,666	20,158	20,662	21,178
Dist Plant Land	2,043,896	2,043,896	2,043,896	2,043,896	2,043,896	2,043,896	2,043,896	2,043,896	2,043,896	2,043,896
Submarine Cables	77,093	79,020	80,996	83,021	85,096	87,224	89,404	91,639	93,930	96,279
Installation Customer Premises	161,542	165,581	169,720	173,963	178,312	182,770	187,339	192,023	196,823	201,744
Martin Land	38,019	38,019	38,019	38,019	38,019	38,019	38,019	38,019	38,019	38,019
Net Book Including Above	2,337,508	2,343,898	2,350,448	2,357,161	2,364,042	2,371,095	2,378,325	2,385,735	2,393,330	2,401,116
	6,234	6,390	6,550	6,713	6,881	7,053	7,230	7,410	7,595	7,785

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CALCUALTION OF NET BOOK VALUE AS OF YEAR END 1996-2001-2011

PG&E Estimated System Avg

$000	1995	1996	1997	1998	1999	2000	2001	2002	2003
	Service Life	Depr Rate OC	Escalation	Depr Adds			Cust Gwt fac		
Inputs	33.3	3.00%	2.50%	2.40%			1.00%		
1.Original Cost 1995/ Capital Additions	8,768,813	269,641	276,382	283,292	290,374	297,633	305,074	312,701	320,518
2. Cummulative Investment w/Replacements		9,038,454	9,314,836	9,598,127	9,888,501	10,186,134	10,491,208	10,803,909	11,124,428
3. New Customer -Avg Impact	4,387,019	43,870	44,309	44,752	45,200	45,651	46,108	46,569	47,035
4. Annual Capital Adds New Customers	4.2000	188,861	195,519	202,411	209,546	216,932	224,579	232,495	240,691
5.Cummalitve Cap Adds New Customers		188.861	384,380	586,790	796,336	1,013,268	1,237,847	1,470,342	1,711,033
3. Depreciation of OC and Capital Additions									
1995		263,064	263,064	263,064	263,064	263,064	263,064	263,064	263,064
1996		11,004	11,004	11,004	11,004	11,004	11,004	11,004	11,004
1997			11,326	11,326	11,326	11,326	11,326	11,326	11,326
1998				11,657	11,657	11,657	11,657	11,657	11,657
1999					11,998	11,998	11,998	11,998	11,998
2000						12,350	12,350	12,350	12,350
2001							12,712	12,712	12,712
2002								13,085	13,085
2003									13,469
2004									
2005									
2006									
2007									
2008									
2009									
2010									
2011									

	1995	1996	1997	1998	1999	2000	2001	2002	2003
Annual Depr 3,587,139	0	274,068	285,394	297,051	309,049	321,399	334,110	347,195	360,664
Cumm Depr	3,587,139	3,861,207	4,146,601	4,443,652	4,752,701	5,074,099	5,408,210	5,755,405	6,116,068
Net Book Value	5,181,674	5,366,108	5,552,614	5,741,266	5,932,136	6,125,303	6,320,845	6,518,847	6,719,392
		3.56%	3.48%	3.40%	3.32%	3.26%	3.19%	3.13%	3.08%
CA Depr	0	11,004	22,330	33,987	45,985	58,334	71,046	84,131	97,600
Cum CA Depr	0	11,004	33,334	56,316	79,971	104,319	129,380	155,176	181,730
Cummulative Customers	4,387,019	4,430,889	4,475,198	4,519,950	4,565,150	4,610,801	4,656,909	4,703,478	4,750,513
Net Book Value Per Customer	$1,181	$1,211	$1,241	$1,270	$1,299	$1,328	$1,357	$1,386	$1,414
Growth Rate Per Customer		2.53%	2.45%	2.37%	2.30%	2.23%	2.17%	2.11%	2.06%
Depreciation Per Customer	$0	$62	$64	$66	$68	$70	$72	$74	$76
CCSF Customers		335,628	337,512	339,396	341,280	343,164	345,048	346,932	348,816
NBV Allocted to CCSF		406,468,315	418,768,947	431,102,680	443,472,740	455,882,471	468,335,334	480,834,911	493,384,907
Depr Expense Allocated to CCSF		20,759,951	21,523,945	22,305,089	23,103,784	23,920,443	24,755,488	25,609,351	26,482,476

1986

PG&E Estimated System Avg

$000		2004	2005	2006	2007	2008	2009	2010	2011	Cummualtive
[Inputs]										
1.Original Cost 1995 Capital Additions		328,531	336,745	345,163	353,792	362,637	371,703	380,996	390,521	13,994,516
2. Cummulative Investment w/Replacements		11,452,959	11,789,704	12,134,867	12,488,659	12,851,296	13,223,000	13,603,995	13,994,516	
3. New Customer -Avg Impact		47,505	47,980	48,460	48,945	49,434	49,928	50,428	50,932	
4. Annual Capital Adds New Customers		249,175	257,958	267,052	276,465	286,210	296,299	306,744	317,557	3,968,498
5.Cummulative Cap Adds New Customers		1,960,208	2,218,166	2,485,218	2,761,683	3,047,893	3,344,193	3,650,937	3,968,493	
3. Depreciation of OC and Capital Additions										
1995		263,064	263,064	263,064	263,064	263,064	263,064	263,064	251,016	
1996		11,004	11,004	11,004	11,004	11,004	11,004	11,004	11,004	
1997		11,326	11,326	11,326	11,326	11,326	11,326	11,326	11,326	
1998		11,657	11,657	11,657	11,657	11,657	11,657	11,657	11,657	
1999		11,998	11,998	11,998	11,998	11,998	11,998	11,998	11,998	
2000		12,350	12,350	12,350	12,350	12,350	12,350	12,350	12,350	
2001		12,712	12,712	12,712	12,712	12,712	12,712	12,712	12,712	
2002		13,085	13,085	13,085	13,085	13,085	13,085	13,085	13,085	
2003		13,469	13,469	13,469	13,469	13,469	13,469	13,469	13,469	
2004		13,865	13,865	13,865	13,865	13,865	13,865	13,865	13,865	
2005			14,273	14,273	14,273	14,273	14,273	14,273	14,273	
2006				14,693	14,693	14,693	14,693	14,693	14,693	
2007					15,126	15,126	15,126	15,126	15,126	
2008						15,572	15,572	15,572	15,572	
2009							16,032	16,032	16,032	
2010								16,506	16,506	
2011									16,994	
		2004	2005	2006	2007	2008	2009	2010	2011	
Annual Depr [3,587,139]		374,529	388,802	403,495	418,621	434,193	450,225	466,731	471,676	9,524,342
Cumm Depr		6,490,597	6,879,399	7,282,894	7,701,515	8,135,709	8,585,934	9,052,665	9,524,342	
Net Book Value		6,922,569	7,128,471	7,337,191	7,548,827	7,763,481	7,981,258	8,202,267	8,438,668	8,438,672
		3.02%	2.97%	2.93%	2.88%	2.84%	2.81%	2.77%	2.88%	
CA Depr		111,464	125,737	140,431	155,557	171,129	187,161	203,667	220,661	
Cum CA Depr		209,064	237,202	266,168	295,987	326,686	358,290	390,828	424,328	
Cummulative Customers		4,798,018	4,845,998	4,894,458	4,943,403	4,992,837	5,042,765	5,093,193	5,144,125	
Net Book Value Per Customer		$1,443	$1,471	$1,499	$1,527	$1,555	$1,583	$1,610	$1,640	
Growth Rate Per Customer		2.00%	1.95%	1.91%	1.87%	1.83%	1.79%	1.75%	1.86%	
Depreciation Per Customer		$78	$80	$82	$85	$87	$89	$92	$92	
CCSF Customers		350,700	352,584	354,468	356,352	358,236	360,120	362,004	363,888	
NBV Allocted to CCSF		505,989,151	518,651,599	531,376,340	544,167,592	557,029,711	569,967,189	582,984,663	596,939,220	
Depr Expense Allocated to CCSF		27,375,319	28,288,346	29,222,036	30,176,878	31,153,375	32,152,043	33,173,410	33,365,707	

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Calculation of Difference between PG&E Net Revenues from CCSF and CCSF's Cost of Service.

	1	2	3	4	5	6	7	8	9	10
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
PG&E Revenues Based on Avg System Cost										
Avg System Net Plant Allocated to CCSF	480,834,911	493,384,907	505,989,151	518,651,599	531,376,340	544,167,592	557,029,711	569,967,189	582,984,663	596,939,220
Net Return on Average Rate Base @ 9.45%	45,441,592	46,627,637	47,818,808	49,015,481	50,218,040	51,426,885	52,642,427	53,865,091	55,095,315	56,414,099
Avg System Dept Expense Allocated to CCSF	25,609,351	26,482,476	27,375,319	28,288,346	29,222,036	30,176,878	31,153,375	32,152,043	33,173,410	33,365,707
Total Return and Depreciation	71,050,943	73,110,113	75,194,128	77,303,827	79,440,076	81,603,762	83,795,802	86,017,134	88,268,726	89,779,806
	1	2	3	4	5	6	7	8	9	10
PG&E COS	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
CCSF Net Plant COS	331,927,449	344,120,462	356,351,804	368,630,056	380,957,765	393,337,610	406,051,928	419,204,528	432,810,712	446,887,994
Net Return on Average Rate Base @	31,369,003	32,521,311	33,677,241	34,837,605	36,002,642	37,172,607	38,374,181	39,617,175	40,903,036	42,233,418
CCSF Depreciation COS	15,434,363	15,919,753	16,916,245	17,943,824	19,010,086	20,116,525	20,985,177	21,796,330	22,640,321	23,516,845
Total Return and Depreciation	46,803,365	48,441,064	50,593,486	52,781,429	55,012,728	57,289,132	59,359,358	61,413,506	63,543,357	65,750,263
	1	2	3	4	5	6	7	8	9	10
Difference Between Allocated Cost and Avg System COS										
1. Return and Depreciation	24,247,577	24,669,050	24,600,641	24,522,398	24,427,347	24,314,630	24,436,443	24,603,628	24,725,368	24,029,543
2. Operating Expenses	2,655,124	2,740,106	2,827,575	2,917,706	3,010,575	3,106,265	3,204,857	3,306,438	3,411,094	3,518,917
									5 year Trend O&M Difference	
Total Net Difference PG&E System Avg v PG&E COS to CCSF	26,902,701	27,409,156	27,428,216	27,440,104	27,437,922	27,420,895	27,641,300	27,910,066	28,136,462	27,548,460
Interest Expense	5,173,403	5,185,805	5,198,761	5,212,108	5,225,902	5,240,196	5,245,331	5,237,857	5,217,403	5,213,140
Preferred Stock Dividend	608,019	609,477	610,999	612,568	614,189	615,869	616,472	615,594	613,190	612,689
Net for Common Equity	21,121,280	21,613,874	21,618,457	21,615,428	21,597,831	21,564,831	21,779,497	22,056,615	22,305,869	21,722,631
Net Present Value 30 Yrs @ 11.60% $180,436,970										
Net Book Value 2001 335,245,705										
Value Based on Net Income Method $495,682,675										

	1	2	3	4	5	6	7	8	9	10
	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Operating Costs	243,279,977	252,221,709	261,266,558	270,386,711	279,577,805	286,448,335	290,657,073	300,476,740	310,391,127	320,402,100
Municipal	246,986,367	256,019,924	265,156,468	274,370,702	283,658,280	290,627,815	294,936,633	304,855,595	314,868,012	324,980,583
PG&E Avg Syste	3,706,390	3,798,215	3,889,910	3,983,991	4,080,475	4,179,479	4,279,560	4,378,855	4,476,885	4,578,483
Difference										

		11	12	13	14	15	16	17	18	19	20
		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
PG&E Revenues Based on Avg System Cost											
Avg System Net Plant Allocated to CCSF		610,992,239	625,376,092	640,098,566	655,167,634	670,591,454	686,378,379	702,536,956	719,075,936	736,004,272	753,331,132
Net Return on Average Rate Base @	9.45%	57,742,188	59,101,543	60,492,899	61,917,010	63,374,648	64,866,601	66,393,677	67,956,703	69,556,525	71,194,011
Avg System Depr Expense Allocated to CCSF		34,262,412	35,183,277	36,128,860	37,099,856	38,096,949	39,120,840	40,172,219	41,251,916	42,360,599	43,499,080
Total Return and Depreciation		92,001,630	94,284,819	96,621,759	99,016,867	101,471,597	103,987,441	106,565,926	109,208,619	111,917,125	114,693,090
		11	12	13	14	15	16	17	18	19	20
PG&E COS		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
CCSF Net Plant COS		461,336,869	476,169,571	491,393,639	507,016,593	523,045,932	539,489,108	556,353,520	573,646,492	591,375,255	609,546,931
Net Return on Average Rate Base @		43,598,918	45,000,691	46,439,451	47,915,907	49,430,770	50,984,742	52,578,523	54,212,806	55,888,273	57,605,598
CCSF Depreciation COS		24,539,067	25,605,723	26,718,744	27,880,146	29,092,030	30,356,593	31,676,123	33,053,010	34,489,747	35,988,936
Total Return and Depreciation		68,137,985	70,606,414	73,158,195	75,796,053	78,522,800	81,341,335	84,254,646	87,265,816	90,378,020	93,594,534
Difference Between Allocated Cost and Avg System COS		11	12	13	14	15	16	17	18	19	20
1. Return and Depreciation		23,866,645	23,678,405	23,463,564	23,220,814	22,948,797	22,646,106	22,311,280	21,942,803	21,539,104	21,098,556
2. Operating Expenses		3,630,454	3,745,526	3,864,246	3,986,729	4,113,094	4,243,464	4,377,966	4,516,732	4,659,896	4,807,598
		3.17%									
Total Net Difference PG&E System Avg v PG&E COS in CCSF		27,497,099	27,423,931	27,327,810	27,207,542	27,061,891	26,889,570	26,689,246	26,459,535	26,199,001	25,906,154
Interest Expense		5,199,387	5,183,793	5,166,366	5,147,123	5,126,086	5,103,286	5,078,763	5,052,568	5,024,759	4,995,408
Preferred Stock Dividend		611,073	609,240	607,192	604,930	602,458	599,778	596,896	593,818	590,549	587,100
Net for Common Equity		21,686,639	21,630,899	21,554,252	21,455,489	21,333,347	21,186,506	21,013,586	20,813,149	20,583,692	20,323,647
Net Present Value 30 Yrs @	11.60% $180,436,970										
Net Book Value 2001	$15,245,705										
Value Based on Net Income Method	$495,682,675										
		11	12	13	14	15	16	17	18	19	20
	Operating Costs	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
	Municipal	331,181,152	342,068,834	353,724,514	364,829,779	376,816,556	389,197,782	401,986,426	415,195,880	428,839,979	442,933,008
	PG&E Avg Syste	335,864,343	346,859,204	358,624,626	369,842,293	381,944,236	394,443,502	407,353,171	420,686,236	434,458,216	448,681,972
	Difference	4,683,191	4,790,370	4,900,111	5,012,514	5,127,681	5,245,719	5,366,744	5,490,875	5,618,238	5,748,964

		21	22	23	24	25	26	27	28	29	30
		2022	2023	2024	2025	2026	2027	2027	2029	2030	2031
PG&E Revenues Based on Avg System Cost											
Avg System Net Plant Allocated to CCSF		771,065,897	789,218,171	807,797,781	826,814,789	846,279,491	866,202,427	886,594,385	907,466,406	928,829,792	950,696,110
Net Return on Average Rate Base @	9.45%	72,870,015	74,585,537	76,341,414	78,138,628	79,978,151	81,860,980	83,788,134	85,760,657	87,779,617	89,846,106
Avg System Depr Expense Allocated to CCSF		44,668,158	45,868,656	47,101,419	48,367,313	49,667,230	51,002,083	52,372,811	53,780,379	55,225,776	56,710,020
Total Return and Depreciation		117,538,203	120,454,193	123,442,833	126,505,941	129,645,381	132,863,063	136,160,945	139,541,036	143,005,393	146,556,127
		21	22	23	24	25	26	27	28	29	30
PG&E COS		2022	2023	2024	2025	2026	2027	2027	2029	2030	2031
CCSF Net Plant COS		628,168,510	647,246,828	666,788,544	686,800,116	707,287,768	728,257,469	749,714,896	771,665,406	794,113,994	817,065,263
Net Return on Average Rate Base @		59,365,412	61,168,450	63,015,251	64,906,457	66,842,655	68,824,409	70,852,256	72,926,702	75,048,220	77,217,243
CCSF Depreciation COS		37,553,291	39,185,644	40,888,953	42,666,300	44,520,904	46,456,124	48,475,463	50,582,578	52,781,284	55,075,563
Total Return and Depreciation		96,918,733	100,354,094	103,904,204	107,572,757	111,363,559	115,280,533	119,327,719	123,509,280	127,829,504	132,292,806
Difference Between Allocated Cost and Avg System COS		21	22	23	24	25	26	27	28	29	30
1 Return and Depreciation		20,619,471	20,100,099	19,538,629	18,933,184	18,281,822	17,582,530	16,833,226	16,031,756	15,175,889	14,263,321
2 Operating Expenses		4,959,982	5,117,195	5,279,392	5,446,730	5,619,371	5,797,485	5,981,245	6,170,829	6,366,422	6,568,214
Total Net Difference PG&E System Avg v PG&E COS in CCSF		25,579,452	25,217,294	24,818,021	24,379,914	23,901,193	23,380,015	22,814,471	22,202,585	21,542,311	20,831,535
Interest Expense		4,961,598	4,932,425	4,898,999	4,864,446	4,828,906	4,792,539	4,755,522	4,718,053	4,680,350	4,642,656
Preferred Stock Dividend		583,479	579,697	575,769	571,708	567,531	563,257	558,906	554,503	550,072	545,641
Net for Common Equity		20,031,376	19,705,171	19,343,252	18,943,760	18,504,756	18,024,219	17,500,043	16,930,029	16,311,889	15,643,237
										5 year trend	-3.30%
Net Present Value 30 Yrs @	11.69% $180,436,970										
Net Book Value 2001	315,245,705										
Value Based on Net Income Method	$195,682,675										
		21	22	23	24	25	26	27	28	29	30
	Operating Costs	2022	2023	2024	2025	2026	2027	2027	2029	2030	2031
	Municipal	457,373,078	472,418,148	487,957,888	504,008,557	520,586,948	537,710,402	555,396,832	573,664,739	592,533,229	612,022,037
	PG&E Avg Syste	463,372,919	478,546,444	494,218,444	510,405,339	527,124,091	544,392,223	562,227,836	580,649,630	599,676,922	619,329,665
	Difference	5,999,840	6,128,296	6,260,556	6,396,781	6,537,143	6,681,821	6,831,004	6,984,891	7,143,692	7,307,628

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			31	32	33	34	35	36	37	38	39	40
		2031	2031	2031	2031	2031	2031	2031	2031	2031	2031	2031
PG&E Revenues Based on Avg System Cost												
Avg System Net Plant Allocated to CCSF												
Net Return on Average Rate Base @	9.45%											
Avg System Depr Expense Allocated to CCSF												
Total Return and Depreciation												
PG&E COS		2031	31 2031	32 2031	33 2031	34 2031	35 2031	36 2031	37 2031	38 2031	39 2031	40 2031
CCSF Net Plant COS												
Net Return on Average Rate Base @												
CCSF Depreciation COS												
Total Return and Depreciation												
Difference Between Allocated Cost and Avg System COS 1. Return and Depreciation 2. Operating Expenses			31	32	33	34	35	36	37	38	39	40
Total Net Difference PG&E System Avg v PG&E COS in CCSF												
Interest Expense												
Preferred Stock Dividend												
Net for Common Equity			15,126,390	14,626,618	14,143,360	13,676,068	13,224,215	12,787,291	12,364,803	11,956,274	11,561,242	11,179,262
Net Present Value 30 Yrs @	11.69%	$180,436,970										
Net Book Value 2001		315,245,705										
Value Based on Net Income Method		$495,682,675										
			31	32	33	34	35	36	37	38	39	40
		2031	2031	2031	2031	2031	2031	2031	2031	2031	2031	2031
	Operating Costs Municipal PG&E Avg Syste Difference											

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Workpapers

NET PRESENT VALUE

Income Method: Results of Analysis		10 Years 2002-2011	15 Years 2002-2016	20 Years 2002-2021	25 Years 2002-2026	30 Years 2002-2031
Discount Rate	13 58%	497,028,085	530,236,212	547,676,386	556,872,274	561,743,261
	12 58%	505,078,885	542,590,053	563,254,312	574,683,527	581,033,687

NOTE We use 12 5% discount rate in Summary Table, i , we discount revenue requirements at 12 5%

	1	2	3	4	5	6	7	8	9	10
This calculation of Income is consistant with Summary Tables X-4 in Chapter 4	24,247,577	24,669,050	24,600,641	24,522,398	24,427,347	24,314,630	24,436,443	24,603,628	24,725,368	24,029,543
	2,655,124	2,740,106	2,827,575	2,907,706	3,010,575	3,106,265	3,204,857	3,306,438	3,411,094	3,518,917
	26,902,701	27,409,156	27,428,216	27,430,104	27,437,922	27,420,895	27,641,300	27,910,066	28,136,462	27,548,460

1992

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Workpapers

Income Method: Results of Analysis

Discount Rate 13.58%

12.50%

NOTE: We use 12.5% discount rate in Summary Table, t
discount revenue requirements at 12.5%

	11	12	13	14	15	16	17	18	19	20
This calculation of Income is consistant with Summary Tables X-4 in Chapter 4	23,866,645	23,678,405	23,463,564	23,220,814	22,948,797	22,646,106	22,311,280	21,942,803	21,539,104	21,098,556
	3,630,819	3,746,279	3,865,410	3,988,330	4,115,159	4,246,021	4,381,045	4,520,362	4,664,109	4,812,428
	27,497,463	27,424,683	27,328,974	27,209,144	27,063,956	26,892,127	26,692,324	26,463,165	26,203,214	25,910,984

Workpapers

Income Method: Results of Analysis

Discount Rate 13.58%

12.50%

NOTE We use 12.5% discount rate in Summary Table, t
discount revenue requirements at 12.5%

	21	22	23	24	25	26	27	28	29	30
This calculation of Income is consistant with Summary Tables X-4 in Chapter 4	20,619,471	20,100,099	19,538,629	18,933,184	18,281,822	17,582,530	16,833,226	16,031,756	15,175,889	14,263,321
	4,965,463	5,123,365	5,286,288	5,454,392	5,627,842	5,806,807	5,991,464	6,181,992	6,378,579	6,581,418
	25,584,934	25,223,464	24,824,917	24,387,576	23,909,663	23,389,337	22,824,690	22,213,748	21,554,469	20,844,739

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Workpapers

STATE BOARD OF EQUALIZATION

1996 ASSESMENT BASED ON 1995 RCNLD

CALCUATION REPRODUCTION COST NEW LESS DEPRECIATION

SUMMARY:	Total Ass'd Value	Gas Ass'd Value	Common Ass'd Value	SF Gen Stations	Electric Ass'd Value
Land @ Market Value	$137,387,983				
Improvements -(From Detail Printout)	727,169,939	$101,803,791	$229,058,531	$119,983,040	$276,324,577
Ratio %	100.00%	14.00%	31.50%	16.50%	38.00%
Personnel Property	61,274,690	8,578,457	19,301,527	10,110,324	23,284,382
Total Excluding Land	788,444,629	110,382,248	248,360,058	130,093,364	299,608,959
Factor Applied to RCNLD 43%	1,833,592,160	256,702,902	577,581,531	302,542,706	696,765,021
Allocate Land	137,387,983	26,733,956	30,000,000	10,000,000	70,654,027
Total Including Land	1,970,980,143	283,436,859	607,581,531	312,542,706	767,419,048
Common Plant (Off Bldg Mrkt St)		97,415,896			
Common Plant (Off Bldg Beale St)		86,565,157			
Hunters Point Gen Station		74,895,809			
Potrero Gen Station		52,387,846			

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Workpapers

Chapter 3

Operations and Maintenance

Workpapers

PG&E Estimated Distribution Expenses from 1996 Test Year Exhibit.

CPUC Acct	$000 2.50% Inflation	1996 Estimated	1996 EOY Cust.	1996 Avg Per Cust (Constant 1993$)	CCSF Factor	CCSF Cost/Cust 1993 $	CCSF Cost/Cust 1996 $ @2.5%	1996 CCSF Customers	1996 Est. CCSF COS
Operations:									
580	Supervision and Engineering	$15,752	4,407.5	$3.57	1.00	$3.57	3.85	335,628	$1,291,729
582	Station Expenses	9,031	4,407.5	2.05	1.00	2.05	2.21	335,628	740,579
583.2	Overhead Line Expenses	13,581	4,407.5	3.08	0.90	2.77	2.99	335,628	1,002,328
583.3	Removing and Resetting Line Trans	6,744	4,407.5	1.53	1.00	1.53	1.65	335,628	553,036
584	Underground Line Expenses	5,232	4,407.5	1.19	0.90	1.07	1.15	335,628	386,141
585	Street Light and Signal Expense	1,713	4,407.5	0.39	1.00	0.39	0.42	167,814	70,237
586	Meter Expense	24,406	4,407.5	5.54	1.00	5.54	5.96	335,628	2,001,393
587.7	Investigation Service Compliants	15,027	4,407.5	3.41	0.90	3.07	3.30	335,628	1,109,049
587.8	Radio & TV Interferrence	52	4,407.5	0.01	1.00	0.01	0.01	335,628	4,264
587.9	Other Work on Customer Premises	0							
588.6	Distribution Maps and Records	9,531	4,407.5	2.16	1.00	2.16	2.33	335,628	781,581
588	Misc Dist Expenses	27,211	4,407.5	6.17	1.00	6.17	6.65	335,628	2,231,415
589	Rents	111	4,407.5	0.03	1.00	0.03	0.03	335,628	9,102
	Total Operations	128,391	4,407.5	29.13		28.36	30.54	335,628	10,180,855
Maintenance:									
590	Supervision and Engineering	9,838	4,407.5	2.23	1.00	2.23	2.40	335,628	806,757
591	Structures and Improvements	1,011	4,407.5	0.23	1.10	0.25	0.27	335,628	91,197
592	Station Equipment	8,835	4,407.5	2.00	1.00	2.00	2.16	335,628	724,507
593.62	Clean Insulations and Buildings	0							
593.63	Replace Line Insulators	0							
593.64	Stubbing Poles	0							
593.65	Moving Poles and Guys	0							
593.66	Pole Trimming	0							
593.67	Emergency Repairs	0							
596.68	Conductor Reconditioning	0							
593.69	Temporary Service Set - Up Work	0							
593.7	Overhaul & Repair Line Equipment	39,692	4,407.5	9.01	0.90	8.10	8.73	335,628	2,929,418
593.71	Paint Poles, Towers and Accsories	15	4,407.5	0.00	0.90	0.00	0.00	335,828	1,107
593.72	Other Overhead Line Maint.	0							
593.73	Tree Timming	38,714	4,407.5	8.78	0.50	4.39	4.73	335,628	1,587,354
593.74	Vegetation Control	1,337	4,407.5	0.30	0.50	0.15	0.16	335,628	54,820
593.76	Right-of-Way Cleaning	151	4,407.5	0.03	0.75	0.03	0.03	335,628	9,287
594	Underground Lines	11,354	4,407.5	2.58	0.90	2.32	2.50	335,628	837,968
595	Line Transformers	2,885	4,407.5	0.65	0.90	0.59	0.63	335,628	212,924
593	Overhead Services	41	4,407.5	0.01	0.90	0.01	0.01	335,628	3,026
594	Underground Services	0							
596	Street Lighting & Signal Systems	1,642	4,407.5	0.37	0.90	0.34	0.36	167,814	60,593
597	Meters	754	4,407.5	0.17	0.90	0.15	0.17	335,628	55,648
598	Misc Dist Equip	12	4,407.5	0.00	1.00	0.00	0.00	335,628	984
	Total Maintenance	116,281	4,407.5	26.38		20.57	22.16	335,628	7,375,588
	Total Opeartions and Maintenance	244,672	4,407.5	55.51		48.94	52.70	335,628	17,556,443

Dist. Labor From Pg 354 95 FERC 1
Direct Payroll :

Oper.	$64,534,461
Maint.	61,162,812
Total	$125,697,273

	Cost Factor	2001 Plant Cost	2001 O&M
Substion O&M - Martin	2.93%	8,175,614	$239,545
Tran Line O&M-UG 230	1.81%	38,071,691	687,194
(This is 3.62% for all Trans ETAG assumed 50% for UG)			
	Total		926,740

Only the unique 230 kv line Is completely allocated to the CCSF. The Martin Substation In like all substions Included In average rates. 687,194

PG&E Estimated Distribution Expenses from 1996 Test Year Exhibit.

CPUC Acct	$000	1996 Estimated	1996 EOY Cust.	Constant 1993$ 1996 Avg Per Cust	1996 CCSF Customers	1996 CCSF Cost Unadj	PG&E COS 1996 $ Esc @2.5%	CCSF Factor	1996 Est. CCSF COS
Operations:									
580	Supervision and Engineering	$15,752	4,407.5	$3.57	335,628	$1,199,499	$1,291,729	1.00	$1,291,729
582	Station Expenses	9,031	4,407.5	2.05	335,628	687,702	740,579	1.00	740,579
583.2	Overhead Line Expenses	13,581	4,407.5	3.08	335,628	1,034,180	1,113,698	0.90	1,002,328
583.3	Removing and Resetting Line Trans	6,744	4,407.5	1.53	335,628	513,549	553,036	1.00	553,036
584	Underground Line Expenses	5,232	4,407.5	1.19	335,628	398,412	429,046	0.90	386,141
585	Street Light and Signal Expense	1,713	4,407.5	0.39	167,814	65,222	70,237	1.00	70,237
586	Meter Expense	24,406	4,407.5	5.54	335,628	1,858,492	2,001,393	1.00	2,001,393
587.7	Investigation Service Compliants	15,027	4,407.5	3.41	335,628	1,144,291	1,232,276	0.90	1,109,049
587.8	Radio & TV Interference	52	4,407.5	0.01	335,628	3,960	4,264	1.00	4,264
587.9	Other Work on Customer Premises	0							
588.6	Distribution Maps and Records	9,531	4,407.5	2.16	335,628	725,776	781,581	1.00	781,581
588	Misc Dist Expenses	27,211	4,407.5	6.17	335,628	2,072,090	2,231,415	1.00	2,231,415
589	Rents	111	4,407.5	0.03	335,628	8,453	9,102	1.00	9,102
	Total Operations	128,391	4,407.5	29.13	335,628	9,776,846	10,528,594		10,180,855
Maintenance:									
590	Supervision and Engineering	9,838	4,407.5	2.23	335,628	749,154	806,757	1.00	806,757
591	Structures and Improvements	1,011	4,407.5	0.23	335,628	76,987	82,906	1.10	91,197
592	Station Equipment	8,835	4,407.5	2.00	335,628	672,776	724,507	1.00	724,507
593.62	Clean Insulations and Buildings	0							
593.63	Replace Line Insulators	0							
593.64	Stubbing Poles	0							
593.65	Moving Poles and Guys	0							
593.66	Pole Trimming	0							
593.67	Emergency Repairs	0							
596.68	Conductor Reconditioning	0							
593.69	Temporary Service Set - Up Work	0							
593.7	Overhaul & Repair Line Equipment	39,692	4,407.5	9.01	335,628	3,022,506	3,254,908	0.90	2,929,418
593.71	Paint Poles, Towers and Accsories	15	4,407.5	0.00	335,628	1,142	1,230	0.90	1,107
593.72	Other Overhead Line Maint.	0							
593.73	Tree Trimming	38,714	4,407.5	8.78	335,628	2,948,032	3,174,708	0.50	1,587,354
593.74	Vegetation Control	1,337	4,407.5	0.30	335,628	101,811	109,640	0.50	54,820
593.76	Right-of-Way Cleaning	151	4,407.5	0.03	335,628	11,498	12,383	0.75	9,287
594	Underground Lines	11,354	4,407.5	2.58	335,628	864,596	931,075	0.90	837,968
595	Line Transformers	2,885	4,407.5	0.65	335,628	219,690	236,582	0.90	212,924
593	Overhead Services	41	4,407.5	0.01	335,628	3,122	3,362	0.90	3,026
594	Underground Services	0							
596	Street Lighting & Signal Systems	1,642	4,407.5	0.37	167,814	62,518	67,325	0.90	60,593
597	Meters	754	4,407.5	0.17	335,628	57,416	61,831	0.90	55,648
598	Misc Dist Equip	12	4,407.5	0.00	335,628	914	984	1.00	984
	Total Maintenance	116,281	4,407.5	26.38	335,628	8,854,682	9,535,524		7,375,588
	Total Opeartions and Maintenance	244,672	4,407.5	55.51	335,628	18,631,527	20,064,117		17,556,443

Dist. Labor From Pg 354 95 FERC 1
Direct Payroll :

Oper.	$64,534,461
Maint.	61,162,812
Total	$125,697,273

	Cost Factor	2001 Plant Cost	2001 O&M
Substion O&M - Martin	2.93%	8,175,614	$239,545
Tran Line O&M-UG 230 kv	1.81%	38,071,691	687,194
(This is 3.62% for all Trans ETAG assumed 50% for UG)			
Total			926,740
Only the unique 230 kv line is completely allocated to the CCSF. The Martin Substation in like all substions included in average rates.			687,194

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PG&E Estimated Distribution Expenses from 1996 Test Year Exhibit.

CPUC Acct	$000 2.50% Inflation	1996 Estimated	1996 EOY Cust.	Constant 1993$ 1996 Avg Per Cust	CCSF Factor	CCSF Cost/Cust 1993 $	CCSF Cost/Cust 1996 $ @2.5%	1996 CCSF Customers	1996 Est. CCSF COS
Operations:									
580	Supervision and Engineering	$15,752	4,407.5	$3.57	1.00	$3.57	3.85	335,628	$1,291,729
582	Station Expenses	9,031	4,407.5	2.05	1.00	2.05	2.21	335,628	740,579
583.2	Overhead Line Expenses	13,581	4,407.5	3.08	0.90	2.77	2.99	335,628	1,002,328
583.3	Removing and Resetting Line Trans	6,744	4,407.5	1.53	1.00	1.53	1.65	335,628	553,036
584	Underground Line Expenses	5,232	4,407.5	1.19	0.90	1.07	1.15	335,628	386,141
585	Street Light and Signal Expense	1,713	4,407.5	0.39	1.00	0.39	0.42	167,814	70,237
586	Meter Expense	24,406	4,407.5	5.54	1.00	5.54	5.96	335,628	2,001,393
587.7	Investigation Service Compliants	15,027	4,407.5	3.41	0.90	3.07	3.30	335,628	1,109,049
587.8	Radio & TV Interferrence	52	4,407.5	0.01	1.00	0.01	0.01	335,628	4,264
587.9	Other Work on Customer Premises	0							
588.6	Distribution Maps and Records	9,531	4,407.5	2.16	1.00	2.16	2.33	335,628	781,581
588	Misc Dist Expenses	27,211	4,407.5	6.17	1.00	6.17	6.65	335,628	2,231,415
589	Rents	111	4,407.5	0.03	1.00	0.03	0.03	335,628	9,102
	Total Operations	128,391	4,407.5	29.13		28.36	30.54	335,628	10,180,855
Maintenance:									
590	Supervision and Engineering	9,838	4,407.5	2.23	1.00	2.23	2.40	335,628	806,757
591	Structures and Improvements	1,011	4,407.5	0.23	1.10	0.25	0.27	335,628	91,197
592	Station Equipment	8,835	4,407.5	2.00	1.00	2.00	2.16	335,628	724,507
593.62	Clean Insulations and Buildings	0							
593.63	Replace Line Insulators	0							
593.64	Stubbing Poles	0							
593.65	Moving Poles and Guys	0							
593.66	Pole Trimming	0							
593.67	Emergency Repairs	0							
596.68	Conductor Reconditioning	0							
593.69	Temporary Service Set - Up Work	0							
593.7	Overhaul & Repair Line Equipment	39,692	4,407.5	9.01	0.90	8.10	8.73	335,628	2,929,418
593.71	Paint Poles, Towers and Accsories	15	4,407.5	0.00	0.90	0.00	0.00	335,628	1,107
593.72	Other Overhead Line Maint.	0							
593.73	Tree Trimming	38,714	4,407.5	8.78	0.50	4.39	4.73	335,628	1,587,354
593.74	Vegetation Control	1,337	4,407.5	0.30	0.50	0.15	0.16	335,628	54,820
593.76	Right-of-Way Cleaning	151	4,407.5	0.03	0.75	0.03	0.03	335,628	9,287
594	Underground Lines	11,354	4,407.5	2.58	0.90	2.32	2.50	335,628	837,968
595	Line Transformers	2,885	4,407.5	0.65	0.90	0.59	0.63	335,628	212,924
593	Overhead Services	41	4,407.5	0.01	0.90	0.01	0.01	335,628	3,026
594	Underground Services	0							
596	Street Lighting & Signal Systems	1,642	4,407.5	0.37	0.90	0.34	0.36	167,814	60,593
597	Meters	754	4,407.5	0.17	0.90	0.15	0.17	335,628	55,648
598	Misc Dist Equip	12	4,407.5	0.00	1.00	0.00	0.00	335,628	984
	Total Maintenance	116,281	4,407.5	26.38		20.57	22.16	335,628	7,375,588
	Total Opeartions and Maintenance	244,672	4,407.5	55.51		48.94	52.70	335,628	17,556,443

Workpapers

CPUC Acct $000 2.50% Inflation	2002 CCSF Customers	PG&E Sys Avg Cost/Cust	2002 PG&E COS Avg Cost/Cust	PG&E Sys Avg Cost To CCSF	PG&E COS in CCSF	2003 Customer Growth Facto 1.00543 Avg Cost To CCSF	2003 COS in CCSF	2004 Customer Growth Facto 1.005372 Avg Cost To CCSF	2004 COS in CCSF	2005 Customer Growth Facto 1.005343 Avg Cost To CCSF	2005 COS in CCSF
Operations:											
580 Supervision and Engineering	346932	$4.46	$4.46	$1,548,463	$1,548,463	1,595,794	1,595,794	1,644,476	1,644,476	1,694,594	1,694,594
582 Station Expenses	346932	2.56	2.56	887,771	887,771	914,907	914,907	942,817	942,817	971,552	971,552
583.2 Overhead Line Expenses	346932	3.85	3.46	1,335,048	1,201,543	1,375,855	1,238,270	1,417,828	1,276,045	1,461,039	1,314,935
583.3 Removing and Resetting Line Trans	346932	1.91	1.91	662,953	662,953	683,217	683,217	704,059	704,059	725,517	725,517
584 Underground Line Expenses	346932	1.48	1.33	514,319	462,887	530,040	477,036	546,210	491,589	562,857	506,571
585 Street Light and Signal Expense	179118	0.49	0.49	86,940	86,940	89,597	89,597	92,330	92,330	95,144	95,144
586 Meter Expense	346932	6.92	6.92	2,399,174	2,399,174	2,472,508	2,472,508	2,547,935	2,547,935	2,625,589	2,625,589
587.7 Investigation Service Compliants	346932	4.26	3.83	1,477,194	1,329,474	1,522,346	1,370,111	1,568,787	1,411,908	1,616,599	1,454,939
587.8 Radio & TV Interference	346932	0.01	0.01	5,112	5,112	5,268	5,268	5,429	5,429	5,594	5,594
587.9 Other Work on Customer Premises											
588.6 Distribution Maps and Records	346932	2.70	2.70	936,922	936,922	965,561	965,561	995,016	995,016	1,025,341	1,025,341
588 Misc Dist Expenses	346932	7.71	7.71	2,674,913	2,674,913	2,756,675	2,756,675	2,840,771	2,840,771	2,927,349	2,927,349
589 Rents	346932	0.03	0.03	10,912	10,912	11,245	11,245	11,588	11,588	11,941	11,941
Total Operations				12,539,721	12,207,064	12,923,012	12,580,188	13,317,247	12,963,965	13,723,117	13,359,067
Maintenance:											
590 Supervision and Engineering	346932	2.79	2.79	967,101	967,101	996,662	996,662	1,027,067	1,027,067	1,058,368	1,058,368
591 Structures and Improvements	346932	0.29	0.32	99,384	109,322	102,422	112,664	105,546	116,101	108,763	119,639
592 Station Equipment	346932	2.50	2.50	868,504	868,504	895,051	895,051	922,355	922,355	950,466	950,466
593.62 Clean Insulations and Buildings											
593.63 Replace Line Insulators											
593.64 Stubbing Poles											
593.65 Moving Poles and Guys											
593.66 Pole Trimming											
593.67 Emergency Repairs											
596.68 Conductor Reconditioning											
593.69 Temporary Service Set - Up Work											
593.7 Overhaul & Repair Line Equipment	346932	11.25	10.12	3,901,828	3,511,645	4,021,092	3,618,983	4,143,761	3,729,385	4,270,051	3,843,046
593.71 Paint Poles, Towers and Accsories	346932	0.00	0.00	1,475	1,327	1,520	1,368	1,566	1,409	1,614	1,452
593.72 Other Overhead Line Maint.											
593.73 Tree Trimming	346932	10.97	5.48	3,805,688	1,902,844	3,922,014	1,961,007	4,041,660	2,020,830	4,164,838	2,082,419
593.74 Vegetation Control	346932	0.38	0.19	131,431	65,715	135,448	67,724	139,580	69,790	143,834	71,917
593.76 Right-of-Way Cleaning	346932	0.04	0.03	14,844	11,133	15,297	11,473	15,764	11,823	16,245	12,183
594 Underground Lines	346932	3.22	2.90	1,116,128	1,004,515	1,150,244	1,035,220	1,185,334	1,066,800	1,221,459	1,099,313
595 Line Transformers	346932	0.82	0.74	283,603	255,243	292,272	263,045	301,188	271,069	310,367	279,331
593 Overhead Services	346932	0.01	0.01	4,030	3,627	4,154	3,738	4,280	3,852	4,411	3,970
594 Underground Services											
596 Street Lighting & Signal Systems	179118	0.47	0.42	83,336	75,002	85,883	77,295	88,503	79,653	91,201	82,081
597 Meters	346932	0.21	0.19	74,120	66,708	76,386	68,747	78,716	70,844	81,115	73,004
598 Misc Dist Equip	346932	0.00	0.00	1,180	1,180	1,216	1,216	1,253	1,253	1,291	1,291
Total Maintenance				11,352,652	8,843,868	11,699,659	9,114,191	12,056,574	9,392,233	12,424,022	9,678,480
Total Opeartions and Maintenance				23,892,372	21,050,932	24,622,672	21,694,380	25,373,821	22,356,197	26,147,139	23,037,547

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Workpapers

Workpapers

CPUC Acct	$000	2006 Customer Growth Facto 1.005315		2007 Customer Growth Facto 1.005287		2008 Customer Growth Facto 1.005259		2009 Customer Growth Facto 1.005232		2010 Customer Growth Facto 1.005204		2011 Customer Growth Facto 1.005177	
	2.50% Inflation	Avg Cost To CCSF	COS in CCSF	Avg Cost To CCSF	COS in CCSF	Avg Cost To CCSF	COS in CCSF	Avg Cost To CCSF	COS in CCSF	Avg Cost To CCSF	COS in CCSF	Avg Cost To CCSF	COS in CCSF
Operations:													
580	Supervision and Engineering	1,746,191	1,746,191	1,799,309	1,799,309	1,853,991	1,853,991	1,910,282	1,910,282	1,968,230	1,968,230	2,027,881	2,027,881
582	Station Expenses	1,001,133	1,001,133	1,031,587	1,031,587	1,062,937	1,062,937	1,095,211	1,095,211	1,128,433	1,128,433	1,162,633	1,162,633
583.2	Overhead Line Expenses	1,505,525	1,354,972	1,551,321	1,396,189	1,598,467	1,438,620	1,647,000	1,482,300	1,696,961	1,527,265	1,748,390	1,573,551
583.3	Removing and Resetting Line Trans	747,607	747,607	770,349	770,349	793,760	793,760	817,861	817,861	842,670	842,670	868,209	868,209
584	Underground Line Expenses	579,994	521,995	597,637	537,874	615,800	554,220	634,497	571,047	653,744	588,370	673,557	606,201
585	Street Light and Signal Expense	98,041	98,041	101,023	101,023	104,094	104,094	107,254	107,254	110,508	110,508	113,857	113,857
586	Meter Expense	2,705,532	2,705,532	2,787,832	2,787,832	2,872,556	2,872,556	2,959,773	2,959,773	3,049,557	3,049,557	3,141,979	3,141,979
587.7	Investigation Service Compliants	1,665,821	1,499,239	1,716,494	1,544,845	1,768,659	1,591,793	1,822,360	1,640,124	1,877,640	1,689,876	1,934,546	1,741,091
587.8	Radio & TV Interferrence	5,764	5,764	5,940	5,940	6,120	6,120	6,306	6,306	6,497	6,497	6,694	6,694
587.9	Other Work on Customer Premises												
588.6	Distribution Maps and Records	1,056,561	1,056,561	1,088,701	1,088,701	1,121,787	1,121,787	1,155,847	1,155,847	1,190,909	1,190,909	1,227,002	1,227,002
588	Misc Dist Expenses	3,016,481	3,016,481	3,108,240	3,108,240	3,202,701	3,202,701	3,299,942	3,299,942	3,400,044	3,400,044	3,503,089	3,503,089
589	Rents	12,305	12,305	12,679	12,679	13,065	13,065	13,461	13,461	13,870	13,870	14,290	14,290
	Total Operations	14,140,957	13,765,823	14,571,112	14,184,566	15,013,936	14,615,644	15,469,795	15,059,409	15,939,063	15,516,228	16,422,126	15,986,477
Maintenance:													
590	Supervision and Engineering	1,090,593	1,090,593	1,123,768	1,123,768	1,157,920	1,157,920	1,193,078	1,193,078	1,229,269	1,229,269	1,266,524	1,266,524
591	Structures and Improvements	112,075	123,282	115,484	127,032	118,993	130,893	122,606	134,867	126,326	138,958	130,154	143,170
592	Station Equipment	979,406	979,406	1,009,198	1,009,198	1,039,868	1,039,868	1,071,441	1,071,441	1,103,943	1,103,943	1,137,400	1,137,400
593.62	Clean Insulations and Buildings												
593.63	Replace Line Insulators												
593.64	Stubbing Poles												
593.65	Moving Poles and Guys												
593.66	Pole Trimming												
593.67	Emergency Repairs												
596.68	Conductor Reconditioning												
593.69	Temporary Service Set - Up Work												
593.7	Overhaul & Repair Line Equipment	4,400,065	3,960,058	4,533,911	4,080,520	4,671,699	4,204,529	4,813,543	4,332,188	4,959,559	4,463,603	5,109,868	4,598,881
593.71	Paint Poles, Towers and Accsories	1,663	1,497	1,713	1,542	1,765	1,589	1,819	1,637	1,874	1,687	1,931	1,738
593.72	Other Overhead Line Maint.												
593.73	Tree Trimming	4,291,648	2,145,824	4,422,196	2,211,098	4,556,589	2,278,295	4,694,938	2,347,469	4,837,357	2,418,678	4,983,962	2,491,981
593.74	Vegetation Control	148,213	74,107	152,722	76,361	157,363	78,682	162,141	81,071	167,060	83,530	172,123	86,061
593.76	Right-of-Way Cleaning	16,739	12,554	17,248	12,936	17,773	13,329	18,312	13,734	18,868	14,151	19,439	14,580
594	Underground Lines	1,258,650	1,132,785	1,296,937	1,167,243	1,336,352	1,202,716	1,376,926	1,239,234	1,418,695	1,276,825	1,461,691	1,315,522
595	Line Transformers	319,817	287,836	329,546	296,591	339,561	305,605	349,871	314,884	360,484	324,436	371,409	334,268
593	Overhead Services	4,545	4,091	4,683	4,215	4,826	4,343	4,972	4,475	5,123	4,611	5,278	4,750
594	Underground Services												
596	Street Lighting & Signal Systems	93,978	84,580	96,836	87,153	99,779	89,801	102,809	92,528	105,927	95,335	109,138	98,224
597	Meters	83,585	75,226	86,127	77,515	88,745	79,870	91,439	82,295	94,213	84,792	97,068	87,362
598	Misc Dist Equip	1,330	1,330	1,371	1,371	1,412	1,412	1,455	1,455	1,499	1,499	1,545	1,545
	Total Maintenance	12,802,307	9,973,169	13,191,742	10,276,543	13,592,646	10,588,854	14,005,351	10,910,356	14,430,196	11,241,316	14,867,530	11,582,005
	Total Opeartions and Maintenance	26,943,264	23,738,992	27,762,853	24,461,110	28,606,583	25,204,497	29,475,146	25,969,766	30,369,259	26,757,545	31,289,656	27,568,482

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Workpapers
Summary of O&M Forecast

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
PG&E Avg Cost to CCSF										
Operations	12,539,721	12,923,012	13,317,247	13,723,117	14,140,957	14,571,112	15,013,936	15,469,795	15,939,063	16,422,126
Maintenance	11,352,652	11,699,659	12,056,574	12,424,022	12,802,307	13,191,742	13,592,646	14,005,351	14,430,196	14,867,530
Total	23,892,372	24,622,672	25,373,821	26,147,139	26,943,264	27,762,853	28,606,583	29,475,146	30,369,259	31,289,656
PG&E COS In CCSF:										
Operations	12,207,064	12,580,188	12,963,965	13,359,067	13,765,823	14,184,566	14,615,644	15,059,409	15,516,228	15,986,477
Maintenance	8,843,868	9,114,191	9,392,233	9,678,480	9,973,169	10,276,543	10,588,854	10,910,356	11,241,316	11,582,005
Total	21,050,932	21,694,380	22,356,197	23,037,547	23,738,992	24,461,110	25,204,497	25,969,766	26,757,545	27,568,482
Incr. O&M UG Trans	687,194	704,374	721,983	740,033	758,534	777,497	796,934	816,858	837,279	858,211
Cust Accts PG&E AvC										
1996 $33.59										
2002 38.96	13,515,873	13,929,002	14,353,926	14,791,390	15,241,757	15,705,397	16,182,693	16,674,038	17,179,837	17,700,503
Cust S & I										
1996 $28.25										
2002 32.76	11,366,078	11,713,496	12,070,832	12,438,715	12,817,448	13,207,343	13,608,721	14,021,915	14,447,262	14,885,113
A&G @ %of PG&E AvC										
O&M,CA, Cl 17.63%	8,597,743	8,860,543	9,130,846	9,409,127	9,695,615	9,990,547	10,294,165	10,606,721	10,928,470	11,259,678
A&G @ %of PG&E COS in CCSF										
O&M,CA, Cl 17.63%	8,096,865	8,344,355	8,598,912	8,860,981	9,130,779	9,408,529	9,694,459	9,988,806	10,291,811	10,603,724
Total Cost PG&E Avg Syst	57,372,065	59,125,712	60,929,426	62,786,372	64,698,084	66,666,140	68,692,163	70,777,820	72,924,828	75,134,950
Total Cost CCSF COS	54,716,941	56,385,606	58,101,851	59,868,666	61,687,509	63,559,875	65,487,306	67,471,383	69,513,734	71,616,033
Difference Avg Sys Cost - CCSF COS	2,655,124	2,740,106	2,827,575	2,917,706	3,010,575	3,106,265	3,204,857	3,306,438	3,411,094	3,518,917

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TOTAL SYSTEM POWER COSTS

07-Jan-97

Fuel Cost Table Reference for Last 6 Tables

Nominal $	Municipal			$ 1995	PG&E		
Year	Expected	Optimistic	Pessimistic	Year	Expected	Optimistic	Pessimistic
2002	183,431,000			2002	199,652,000		
2003	190,537,000			2003	205,570,000		
2004	197,695,000			2004	211,553,000		
2005	204,876,000			2005	217,519,000		
2006	212,076,000			2006	223,458,000		
2007	216,912,000			2007	227,029,000		
2008	219,042,000			2008	218,277,000		
2009	226,694,000			2009	224,735,000		
2010	234,377,000			2010	231,195,000		
2011	242,091,000			2011	237,653,000		
2012	250,497,000			2012	244,771,000		
2013	258,941,000			2013	251,903,000		
2014	268,077,000			2014	259,691,000		
2015	276,591,000			2015	266,824,000		

FROM : RESOURCE DECISIONS, M. FELLMAN PHONE NO. : 415 282 6310 F01

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Table 3A-1

Projected Energy Use for CCSF

	Peak Load (MW)	Total (GWh)	Small (GWh)	Large (GWh)	HH Load (GWh)
1990	892	4,363	2,639	1,724	573
1991	879	4,299	2,601	1,699	564
1992	885	4,327	2,618	1,710	568
1993	882	4,313	2,609	1,704	566
1994	881	4,308	2,606	1,702	565
1995	882	4,313	2,609	1,704	566
1996	883	4,319	2,613	1,706	567
1997	884	4,324	2,616	1,708	567
1998	886	4,330	2,619	1,711	568
1999	891	4,357	2,636	1,722	572
2000	897	4,385	2,653	1,733	575
2001	903	4,413	2,670	1,744	579
2002	908	4,441	2,686	1,755	583
2003	914	4,469	2,703	1,766	586
2004	920	4,497	2,720	1,777	590
2005	925	4,525	2,737	1,788	594
2006	931	4,553	2,754	1,799	597
2007	937	4,580	2,771	1,810	601
2008	943	4,608	2,788	1,821	605
2009	948	4,636	2,804	1,832	608
2010	954	4,664	2,821	1,843	612
2011	960	4,692	2,838	1,854	616
2012	965	4,720	2,855	1,865	619
2013	971	4,748	2,872	1,876	623
2014	977	4,776	2,889	1,887	627
2015	982	4,803	2,906	1,898	630

Source for Capacity Forecast: PG&E
1996 Test Year General Rate Case, P.432

11.6%

Workpapers

Chapter 4

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Cash Flow Analysis

	1	2	3	4	5
	2002	2003	2004	2005	2006
Base Case					
Internal Cash Flow:					
Depreciation:					
Depr NBV	15,434,363	15,919,753	16,916,245	17,943,824	19,010,086
Depreciation 20 Diff	25,295,000	26,445,000	26,445,000	26,445,000	26,445,000
Amortization Developmt	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000
Total Cash Flow	41,879,363	43,514,753	44,511,245	45,538,824	46,605,086
Capital Requirements:					
Captial Additions	27,116,107	28,112,766	29,147,588	30,222,076	31,337,795
Changes in Working Capital	0	745,760	754,136	760,390	766,275
Inventory	6,000,000	6,281,128	6,572,604	6,874,824	7,188,202
Changes in Inventory	6,000,000	281,128	291,476	302,221	313,378
Total Changes in WC and Inv	0	1,026,888	1,045,612	1,062,611	1,079,653
Bond Retirements (Mort Basis)	Components =	$794.5 million condemnation + $26.4 million for inventory and worki			
Bonds Issued = $843.9 million		capital + $23 million for development costs. Note:WC/Inv evergreen			
Principal Balance- Beg of Year	843.9	838.0	831.6	824.8	817.4
30 Year Mortgage Payment:	69.2	69.2	69.2	69.2	69.2
Interest @ 7.5%	63.3	62.8	62.4	61.9	61.3
Principal Payment	5.9	6.4	6.8	7.4	7.9
Principal Balance- End of Year	838.0	831.6	824.8	817.4	809.5
Total Capital Requirements	33,042,607	35,510,641	37,042,011	38,647,159	40,332,106
New Bond Issues	($8,836,756)	($8,004,112)	($7,469,234)	($6,891,665)	($6,272,980)

Cash Flow Analysis -Base Case

	1	2	3	4	5
	2002	2003	2004	2005	2006
Internal Cash Flow From:					
1. Book Depreciation SL	$40,562,215	$41,047,605	$42,044,098	$43,071,677	$44,137,939
Capital Requirements:					
1. Capital Additions	27,116,107	28,112,766	29,147,588	30,222,076	31,337,795
2. Principal Payments on 30 yr Bonds *	5,926,500	6,370,987	6,848,812	7,362,472	7,914,658
3. Changes in Working Capital	0	745,760	754,136	760,390	766,275
4. Changes in Inventory	0	281,128	291,476	302,221	313,378
Total Capital Requirements	33,042,607	35,510,641	37,042,011	38,647,159	40,332,106
Net Cash Flow	$7,519,608	$5,536,964	$5,002,087	$4,424,517	$3,805,833

* Bonds Issued for:

a. Purchase of System from PG&E	$794.5	Million
b. Initial Inventory and Working Capital *	26.4	"
b. Development & Litigation Costs	23.0	"
Total	$843.9	Million

*Note that portion of bond issues for Initial Inventory and Working Capital is Rolled Over Each Year and not part of principal repayment.

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Workpapers
Estimate of Revenue Requirements 2002 - 2011
Municipal Versus PG&E - Base Case
Transfer Price RCNLD - Straight Line Depreciation

	Net Present Value @12.5%	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Municipal Costs											
Distribution O&M Expense		$21,050,932	$21,694,380	$22,356,197	$23,037,547	$23,738,992	$24,461,110	$25,204,497	$25,969,766	$26,757,545	$27,568,482
System Power, Transmission & CTC		183,431,000	190,537,000	197,695,000	204,876,000	212,076,000	216,912,000	219,042,000	226,694,000	234,377,000	242,091,000
Franchise Fees and Property Tax		6,489,409	6,672,675	6,857,131	7,042,695	7,229,391	7,405,371	7,568,977	7,761,409	7,955,273	8,155,515
Customer Accounts Expense		13,515,873	13,929,002	14,353,926	14,791,930	15,241,757	15,705,397	16,182,693	16,674,038	17,179,837	17,700,503
Customer Service & Info Expense		11,366,078	11,713,496	12,070,832	12,438,715	12,817,448	13,207,343	13,608,721	14,021,915	14,447,262	14,885,113
Administrative and General Expense		7,808,590	8,047,269	8,292,762	8,545,593	8,805,693	9,073,555	9,349,305	9,633,172	9,925,389	10,226,197
SF Transmission O&M		687,194	704,374	721,983	740,033	758,534	777,497	796,934	816,858	837,279	858,211
Total Operating Costs		244,349,076	253,298,196	262,347,831	271,472,512	280,667,815	287,542,272	291,753,127	301,571,158	311,479,586	321,485,021
Depreciation - Plant and Equipment		39,412,215	39,897,605	40,894,098	41,921,677	42,987,939	44,094,378	44,963,030	45,774,183	46,618,174	47,494,698
Amortization of Capitalzed Development Costs		1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000
Interest on Debt		60,389,173	59,419,060	58,451,822	57,488,102	56,528,091	55,571,990	54,640,975	53,742,831	52,878,706	52,049,913
Total Revenue Requirements	$2,078,380,392	$345,300,464	$353,764,861	$362,843,751	$372,032,291	$381,333,845	$388,358,640	$392,507,132	$402,238,172	$412,126,466	$422,179,632
PG&E Costs											
Distribution O&M Expense		$23,892,372	$24,622,672	$25,373,821	$26,147,139	$26,943,264	$27,762,853	$28,606,583	$29,475,146	$30,369,259	$31,289,656
System Power, Transmission & CTC		183,431,000	190,537,000	197,695,000	204,876,000	212,076,000	216,912,000	219,042,000	226,694,000	234,377,000	242,091,000
Franchise Fees and Property Tax		6,489,409	6,672,675	6,857,131	7,042,695	7,229,391	7,405,371	7,568,977	7,761,409	7,955,273	8,155,515
Customer Accounts Expense		13,515,873	13,929,002	14,353,926	14,791,930	15,241,757	15,705,397	16,182,693	16,674,038	17,179,837	17,700,503
Customer Service & Info Expense		11,366,078	11,713,496	12,070,832	12,438,715	12,817,448	13,207,343	13,608,721	14,021,915	14,447,262	14,885,113
Administrative and General Expense		8,291,635	8,545,079	8,805,758	9,074,223	9,350,420	9,634,851	9,927,659	10,229,087	10,539,381	10,858,796
Total Operating Costs		246,986,367	256,019,924	265,156,468	274,370,702	283,658,280	290,627,815	294,936,633	304,855,595	314,868,012	324,980,583
Depreciation		25,609,351	26,482,476	27,375,319	28,288,346	29,222,036	30,176,878	31,153,375	32,152,043	33,173,410	33,365,707
Return and Income Tax		65,297,381	67,001,670	68,713,327	70,432,887	72,160,907	73,897,959	75,644,635	77,401,544	79,169,317	81,064,346
Total Revenue Requirements	$2,092,476,425	$337,893,099	$349,504,071	$361,245,114	$373,091,936	$385,041,223	$394,702,651	$401,734,643	$414,409,182	$427,210,739	$439,410,636
Annual Revenue Requirement Difference Municipal versus PG&E	($14,096,033)	7,407,365	4,260,790	1,598,636	(1,059,645)	(3,707,378)	(6,344,011)	(9,227,511)	(12,171,010)	(15,084,274)	(17,231,005)

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Municipal Costs	Net Present Value @12.5%	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Distribution O&M Expense		$28,405,535	$29,268,003	$30,156,657	$31,072,294	$32,015,732	$32,987,815	$33,989,413	$35,021,422	$36,084,766	$37,180,396
System Power, Transmission & CTC		250,497,000	258,941,000	268,077,000	276,591,000	285,905,596	295,533,873	305,486,397	315,774,086	326,408,228	337,400,490
Franchise Fees and Property Tax		8,364,149	8,576,988	8,797,398	9,018,910	9,248,738	9,484,553	9,726,514	9,974,785	10,229,536	10,490,940
Customer Accounts Expense		18,237,937	18,791,690	19,362,256	19,950,146	20,555,885	21,180,017	21,823,098	22,485,706	23,168,432	23,871,887
Customer Service & Info Expense		15,337,065	15,802,739	16,282,552	16,776,934	17,286,326	17,811,185	18,351,980	18,909,195	19,483,329	20,074,895
Administrative and General Expense		10,536,691	10,856,613	11,186,249	11,525,893	11,875,850	12,236,433	12,607,964	12,990,775	13,385,210	13,791,620
SF Transmission O&M		879,666	901,658	924,200	947,305	970,987	995,262	1,020,143	1,045,647	1,071,788	1,098,583
Total Operating Costs		332,258,044	343,138,690	354,786,312	365,882,481	377,859,114	390,229,137	403,005,510	416,201,617	429,831,289	443,908,811
Depreciation - Plant and Equipment		48,516,920	49,583,576	50,696,597	51,857,998	53,069,883	54,334,445	55,653,975	57,030,862	58,467,600	59,966,788
Amortization of Capitalzed Development Costs		1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000
Interest on Debt		51,248,990	50,476,854	49,734,070	49,021,202	48,338,814	47,687,463	47,067,705	46,480,089	45,925,157	45,403,444
Total Revenue Requirements	$2,078,380,392	$433,173,953	$444,349,120	$456,366,978	$467,911,682	$480,417,811	$493,401,046	$506,877,190	$520,862,569	$535,374,046	$550,429,044

PG&E Costs	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Distribution O&M Expense	$32,239,694	$33,218,577	$34,227,181	$35,266,410	$36,337,193	$37,440,487	$38,577,280	$39,748,589	$40,955,463	$42,198,980
System Power, Transmission & CTC	250,497,000	258,941,000	268,077,000	276,591,000	285,905,596	295,533,873	305,486,397	315,774,086	326,408,228	337,400,490
Franchise Fees and Property Tax	8,364,149	8,576,988	8,797,398	9,018,910	9,248,738	9,484,553	9,726,514	9,974,785	10,229,536	10,490,940
Customer Accounts Expense	18,237,937	18,791,690	19,362,256	19,950,146	20,555,885	21,180,017	21,823,098	22,485,706	23,168,432	23,871,887
Customer Service & Info Expense	15,337,065	15,802,739	16,282,552	16,776,934	17,286,326	17,811,185	18,351,980	18,909,195	19,483,329	20,074,895
Administrative and General Expense	11,188,498	11,528,211	11,878,238	12,238,893	12,610,499	12,993,387	13,387,901	13,794,393	14,213,228	14,644,780
Total Operating Costs	335,864,343	346,859,204	358,624,626	369,842,293	381,944,236	394,443,502	407,353,171	420,686,756	434,458,216	448,681,972
Depreciation	34,262,442	35,183,277	36,128,860	37,099,856	38,096,949	39,120,840	40,172,249	41,251,916	42,360,599	43,499,080
Return and Income Tax	82,972,746	84,926,073	86,925,385	88,971,765	91,066,319	93,210,184	95,404,519	97,650,512	99,949,380	102,302,368
Total Revenue Requirements	$2,092,476,425	$453,099,531	$466,968,554	$481,678,871	$495,913,914	$511,107,505	$526,774,526	$542,929,939	$559,589,183	$576,768,196	$594,483,419
Annual Revenue Requirement Difference Municipal versus PG&E	($14,096,033)	(19,925,577)	(22,619,434)	(25,311,892)	(28,002,232)	(30,689,694)	(33,373,480)	(36,052,748)	(38,726,615)	(41,394,149)	(44,054,375)

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	Net Present Value @12.5%	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Municipal Costs											
Distribution O&M Expense		$38,309,292	$39,472,465	$40,670,954	$41,905,833	$43,178,206	$44,489,211	$45,840,023	$47,231,848	$48,665,933	$50,143,561
System Power, Transmission & CTC		348,762,931	360,508,019	372,648,640	385,198,113	398,170,208	411,579,156	425,439,670	439,766,957	454,576,735	469,885,253
Franchise Fees and Property Tax		10,759,176	11,034,425	11,316,877	11,606,725	11,904,168	12,209,410	12,522,661	12,844,136	13,174,058	13,512,654
Customer Accounts Expense		24,596,702	25,343,523	26,113,020	26,905,881	27,722,815	28,564,554	29,431,850	30,325,480	31,246,242	32,194,961
Customer Service & Info Expense		20,684,422	21,312,456	21,959,559	22,626,310	23,313,305	24,021,159	24,750,506	25,501,997	26,276,306	27,074,125
Administrative and General Expense		14,210,371	14,641,835	15,086,401	15,544,464	16,016,435	16,502,737	17,003,804	17,520,085	18,052,042	18,600,150
SF Transmission O&M		1,126,047	1,154,199	1,183,054	1,212,630	1,242,946	1,274,019	1,305,870	1,338,516	1,371,979	1,406,279
Total Operating Costs		458,448,941	473,466,923	488,978,505	504,999,957	521,548,084	538,640,248	556,294,384	574,529,020	593,363,295	612,816,982
Depreciation - Plant and Equipment		37,553,291	39,185,644	40,888,953	42,666,300	44,520,904	46,456,124	48,475,463	50,582,578	52,781,284	55,075,563
Amortization of Capitalzed Development Costs											
Interest on Debt		46,713,813	48,144,686	49,610,315	51,111,183	52,647,757	54,220,485	55,829,792	57,476,080	59,159,724	60,881,069
Total Revenue Requirements	$2,078,380,392	$542,716,044	$560,797,254	$579,477,773	$598,777,440	$618,716,745	$639,316,856	$660,599,638	$682,587,677	$705,304,303	$728,773,615
PG&E Costs		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Distribution O&M Expense		$43,480,254	$44,800,430	$46,160,691	$47,562,253	$49,006,370	$50,494,334	$52,027,477	$53,607,170	$55,234,827	$56,911,904
System Power, Transmission & CTC		348,762,931	360,508,019	372,648,640	385,198,113	398,170,208	411,579,156	425,439,670	439,766,957	454,576,735	469,885,253
Franchise Fees and Property Tax		10,759,176	11,034,425	11,316,877	11,606,725	11,904,168	12,209,410	12,522,661	12,844,136	13,174,058	13,512,654
Customer Accounts Expense		24,596,702	25,343,523	26,113,020	26,905,881	27,722,815	28,564,554	29,431,850	30,325,480	31,246,242	32,194,961
Customer Service & Info Expense		20,684,422	21,312,456	21,959,559	22,626,310	23,313,305	24,021,159	24,750,506	25,501,997	26,276,306	27,074,125
Administrative and General Expense		15,089,434	15,547,590	16,019,656	16,506,056	17,007,223	17,523,608	18,055,672	18,603,890	19,168,754	19,750,768
Total Operating Costs		463,372,919	478,546,444	494,218,444	510,405,339	527,124,091	544,392,223	562,227,836	580,649,630	599,676,922	619,329,665
Depreciation		44,668,158	45,868,656	47,101,419	48,367,313	49,667,230	51,002,083	52,372,811	53,780,379	55,225,776	56,710,020
Return and Income Tax		104,710,749	107,175,828	109,698,939	112,281,448	114,924,755	117,630,290	120,399,517	123,233,938	126,135,086	129,104,532
Total Revenue Requirements	$2,092,476,425	$612,751,825	$631,590,928	$651,018,801	$671,054,100	$691,716,075	$713,024,595	$735,000,165	$757,663,947	$781,037,784	$805,144,218
Annual Revenue Requirement Difference											
Municipal versus PG&E	($14,096,033)	(70,035,781)	(70,793,674)	(71,541,028)	(72,276,660)	(72,999,330)	(73,707,739)	(74,400,526)	(75,076,270)	(75,733,481)	(76,370,603)

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Workpapers

Estimate of Revenue Requirements 2002 - 2011

Municipal Versus PG&E - High Cost Case

Transfer Price RCNLD - Sinking Fund Depreciation

	Net Present Value @12.5%	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Municipal Costs											
Distribution O&M Expense		$21,050,932	$21,694,380	$22,356,197	$23,037,547	$23,738,992	$24,461,110	$25,204,497	$25,969,766	$26,757,545	$27,568,482
System Power, Transmission & CTC		183,431,000	190,537,000	197,695,000	204,876,000	212,076,000	216,912,000	219,042,000	226,694,000	234,377,000	242,091,000
Franchise Fees and Property Tax		6,489,409	6,672,675	6,857,131	7,042,695	7,229,391	7,405,371	7,568,977	7,761,409	7,955,273	8,155,515
Customer Accounts Expense		13,515,873	13,929,002	14,353,926	14,791,930	15,241,757	15,705,397	16,182,693	16,674,038	17,179,837	17,700,503
Customer Service & Info Expense		11,366,078	11,713,496	12,070,832	12,438,715	12,817,448	13,207,343	13,608,721	14,021,915	14,447,262	14,885,113
Administrative and General Expense		7,808,590	8,047,269	8,292,762	8,545,593	8,805,693	9,073,555	9,349,305	9,633,172	9,925,389	10,226,197
SF Transmission O&M		687,194	704,374	721,983	740,033	758,534	777,497	796,934	816,858	837,279	858,211
Total Operating Costs		244,349,076	253,298,196	262,347,831	271,472,512	280,667,815	287,542,272	291,753,127	301,571,158	311,479,586	321,485,021
Depreciation - Plant and Equipment		49,599,345	50,084,735	51,081,227	52,108,806	53,175,068	54,281,507	55,150,159	55,961,312	56,805,303	57,681,827
Amortization of Capitalized Development Costs		1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000
Interest on Debt		74,928,332	73,194,185	71,462,912	69,735,157	68,011,111	66,290,976	64,595,926	62,933,748	61,305,588	59,712,760
Total Revenue Requirements	$2,200,258,101	$370,026,753	$377,727,116	$386,041,970	$394,466,475	$403,003,995	$409,264,755	$412,649,213	$421,616,218	$430,740,477	$440,029,608
PG&E Costs											
Distribution O&M Expense		$23,892,372	$24,622,672	$25,373,821	$26,147,139	$26,943,264	$27,762,853	$28,606,583	$29,475,146	$30,369,259	$31,289,656
System Power, Transmission & CTC		183,431,000	190,537,000	197,695,000	204,876,000	212,076,000	216,912,000	219,042,000	226,694,000	234,377,000	242,091,000
Franchise Fees and Property Tax		6,489,409	6,672,675	6,857,131	7,042,695	7,229,391	7,405,371	7,568,977	7,761,409	7,955,273	8,155,515
Customer Accounts Expense		13,515,873	13,929,002	14,353,926	14,791,930	15,241,757	15,705,397	16,182,693	16,674,038	17,179,837	17,700,503
Customer Service & Info Expense		11,366,078	11,713,496	12,070,832	12,438,715	12,817,448	13,207,343	13,608,721	14,021,915	14,447,262	14,885,113
Administrative and General Expense		8,291,635	8,545,079	8,805,758	9,074,223	9,350,420	9,634,851	9,927,659	10,229,087	10,539,381	10,858,796
Total Operating Costs		246,986,367	256,019,924	265,156,468	274,370,702	283,658,280	290,627,815	294,936,633	304,855,595	314,868,012	324,980,583
Depreciation		25,609,351	26,482,476	27,375,319	28,288,346	29,222,036	30,176,878	31,153,375	32,152,043	33,173,410	33,365,707
Return and Income Tax		65,297,381	67,091,670	68,713,327	70,432,887	72,160,907	73,897,959	75,644,635	77,401,544	79,169,317	81,064,346
Total Revenue Requirements	$2,092,476,425	$337,893,099	$349,594,071	$361,245,114	$373,091,936	$385,041,223	$394,702,651	$401,734,643	$414,409,182	$427,210,739	$439,410,636
Annual Revenue Requirement Difference											
Municipal versus PG&E	$107,781,676	32,133,654	28,223,045	24,796,856	21,374,540	17,962,772	14,562,104	10,914,570	7,207,036	3,529,737	618,972

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	Net Present Value @12.5%	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Municipal Costs											
Distribution O&M Expense		$28,405,535	$29,268,003	$30,156,657	$31,072,294	$32,015,732	$32,987,815	$33,989,413	$35,021,422	$36,084,766	$37,180,396
System Power, Transmission & CTC		250,497,000	258,941,000	268,077,000	276,591,000	285,905,596	295,533,873	305,486,397	315,774,086	326,408,228	337,400,490
Franchise Fees and Property Tax		8,364,149	8,576,988	8,797,398	9,018,910	9,248,738	9,484,553	9,726,514	9,974,785	10,229,536	10,490,940
Customer Accounts Expense		18,237,937	18,791,690	19,362,256	19,950,146	20,555,885	21,180,017	21,823,098	22,485,706	23,168,432	23,871,887
Customer Service & Info Expense		15,337,065	15,802,739	16,282,552	16,776,934	17,286,326	17,811,185	18,351,980	18,909,195	19,483,329	20,074,895
Administrative and General Expense		10,536,691	10,856,613	11,186,249	11,525,893	11,875,850	12,236,433	12,607,964	12,990,775	13,385,210	13,791,620
SF Transmission O&M		879,666	901,658	924,200	947,305	970,987	995,262	1,020,143	1,045,647	1,071,788	1,098,583
Total Operating Costs		332,258,044	343,138,690	354,786,312	365,882,481	377,859,114	390,229,137	403,005,510	416,201,617	429,831,289	443,908,811
Depreciation - Plant and Equipment		58,704,049	59,770,705	60,883,726	62,045,127	63,257,012	64,521,575	65,841,105	67,217,992	68,654,729	70,153,918
Amortization of Capitalized Development Costs		1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000
Interest on Debt		58,147,802	56,611,631	55,104,813	53,627,911	52,181,487	50,766,102	49,382,309	48,030,659	46,711,692	45,425,944
Total Revenue Requirements	$2,200,258,101	$450,259,895	$460,671,027	$471,924,851	$482,705,519	$494,447,614	$506,666,814	$519,378,924	$532,600,268	$546,347,710	$560,638,673
PG&E Costs											
Distribution O&M Expense		$32,239,694	$33,218,577	$34,227,181	$35,266,410	$36,337,193	$37,440,487	$38,577,280	$39,748,589	$40,955,463	$42,198,980
System Power, Transmission & CTC		250,497,000	258,941,000	268,077,000	276,591,000	285,905,596	295,533,873	305,486,397	315,774,086	326,408,228	337,400,490
Franchise Fees and Property Tax		8,364,149	8,576,988	8,797,398	9,018,910	9,248,738	9,484,553	9,726,514	9,974,785	10,229,536	10,490,940
Customer Accounts Expense		18,237,937	18,791,690	19,362,256	19,950,146	20,555,885	21,180,017	21,823,098	22,485,706	23,168,432	23,871,887
Customer Service & Info Expense		15,337,065	15,802,739	16,282,552	16,776,934	17,286,326	17,811,185	18,351,980	18,909,195	19,483,329	20,074,895
Administrative and General Expense		11,188,498	11,528,211	11,878,238	12,238,893	12,610,499	12,993,387	13,387,901	13,794,393	14,213,228	14,644,780
Total Operating Costs		335,864,343	346,859,204	358,624,626	369,842,293	381,944,236	394,443,502	407,353,171	420,686,756	434,458,216	448,681,972
Depreciation		34,262,442	35,183,277	36,128,860	37,099,856	38,096,949	39,120,840	40,172,249	41,251,916	42,360,599	43,499,080
Return and Income Tax		82,972,746	84,926,073	86,925,385	88,971,765	91,066,319	93,210,184	95,404,519	97,650,512	99,949,380	102,302,368
Total Revenue Requirements	$2,092,476,425	$453,099,531	$466,968,554	$481,678,871	$495,913,914	$511,107,505	$526,774,526	$542,929,939	$559,589,183	$576,768,196	$594,483,419
Annual Revenue Requirement Difference Municipal versus PG&E	$107,781,676	(2,839,635)	(6,297,527)	(9,754,020)	(13,208,394)	(16,659,891)	(20,107,712)	(23,551,015)	(26,988,916)	(30,420,485)	(33,844,746)

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	Net Present Value @12.5%	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Municipal Costs											
Distribution O&M Expense		$38,309,292	$39,472,465	$40,670,954	$41,905,833	$43,178,206	$44,489,211	$45,840,023	$47,231,848	$48,665,933	$50,143,561
System Power, Transmission & CTC		348,762,931	360,508,019	372,648,640	385,198,113	398,170,208	411,579,156	425,439,670	439,766,957	454,576,735	469,885,253
Franchise Fees and Property Tax		10,759,176	11,034,425	11,316,877	11,606,725	11,904,168	12,209,410	12,522,661	12,844,136	13,174,058	13,512,654
Customer Accounts Expense		24,596,702	25,343,523	26,113,020	26,905,881	27,722,815	28,564,554	29,431,850	30,325,480	31,246,242	32,194,961
Customer Service & Info Expense		20,684,422	21,312,456	21,959,559	22,626,310	23,313,305	24,021,159	24,750,506	25,501,997	26,276,306	27,074,125
Administrative and General Expense		14,210,371	14,641,835	15,086,401	15,544,464	16,016,435	16,502,737	17,003,804	17,520,085	18,052,042	18,600,150
SF Transmission O&M		1,126,047	1,154,199	1,183,054	1,212,630	1,242,946	1,274,019	1,305,870	1,338,516	1,371,979	1,406,279
Total Operating Costs		458,448,941	473,466,923	488,978,505	504,999,957	521,548,084	538,640,248	556,294,384	574,529,020	593,363,295	612,816,982
Depreciation - Plant and Equipment		37,553,291	39,185,644	40,888,953	42,666,300	44,520,904	46,456,124	48,475,463	50,582,578	52,781,284	55,075,563
Amortization of Capitalized Development Costs		0	0	0	0	0	0	0	0	0	0
Interest on Debt		46,736,313	48,167,186	49,632,815	51,133,683	52,670,257	54,242,985	55,852,292	57,498,580	59,182,224	60,903,569
Total Revenue Requirements	$2,200,258,101	$542,738,544	$560,819,754	$579,500,273	$598,799,940	$618,739,245	$639,339,356	$660,622,138	$682,610,177	$705,326,803	$728,796,115
PG&E Costs											
Distribution O&M Expense		$43,480,254	$44,800,430	$46,160,691	$47,562,253	$49,006,370	$50,494,334	$52,027,477	$53,607,170	$55,234,827	$56,911,904
System Power, Transmission & CTC		348,762,931	360,508,019	372,648,640	385,198,113	398,170,208	411,579,156	425,439,670	439,766,957	454,576,735	469,885,253
Franchise Fees and Property Tax		10,759,176	11,034,425	11,316,877	11,606,725	11,904,168	12,209,410	12,522,661	12,844,136	13,174,058	13,512,654
Customer Accounts Expense		24,596,702	25,343,523	26,113,020	26,905,881	27,722,815	28,564,554	29,431,850	30,325,480	31,246,242	32,194,961
Customer Service & Info Expense		20,684,422	21,312,456	21,959,559	22,626,310	23,313,305	24,021,159	24,750,506	25,501,997	26,276,306	27,074,125
Administrative and General Expense		15,089,434	15,547,590	16,019,656	16,506,056	17,007,223	17,523,608	18,055,672	18,603,890	19,168,754	19,750,768
Total Operating Costs		463,372,919	478,546,444	494,218,444	510,405,339	527,124,091	544,392,223	562,227,836	580,649,630	599,676,922	619,329,665
Depreciation		44,668,158	45,868,656	47,101,419	48,367,313	49,667,230	51,002,083	52,372,811	53,780,379	55,225,776	56,710,020
Return and Income Tax		104,710,749	107,175,828	109,698,939	112,281,448	114,924,755	117,630,290	120,399,517	123,233,938	126,135,086	129,104,532
Total Revenue Requirements	$2,092,476,425	$612,751,825	$631,590,928	$651,018,801	$671,054,100	$691,716,075	$713,024,595	$735,000,165	$757,663,947	$781,037,784	$805,144,218
Annual Revenue Requirement Difference											
Municipal versus PG&E	$107,781,676	(70,013,281)	(70,771,174)	(71,518,528)	(72,254,160)	(72,976,830)	(73,685,239)	(74,378,026)	(75,053,770)	(75,710,981)	(76,348,103)

Workpapers
Estimate of Revenue Requirements 2002 - 2011
Municipal Versus PG&E - Lower Boundary
Transfer Price Net Book Value

	Net Present Value @12.5%	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Municipal Costs											
Distribution O&M Expense		$21,050,932	$21,694,380	$22,356,197	$23,037,547	$23,738,992	$24,461,110	$25,204,497	$25,969,766	$26,757,545	$27,568,482
System Power, Transmission & CTC		183,431,000	190,537,000	197,695,000	204,876,000	212,076,000	216,912,000	219,042,000	226,694,000	234,377,000	242,091,000
Franchise Fees and Property Tax		6,489,409	6,672,675	6,857,131	7,042,695	7,229,391	7,405,371	7,568,977	7,761,409	7,955,273	8,155,515
Customer Accounts Expense		13,515,873	13,929,002	14,353,926	14,791,930	15,241,757	15,705,397	16,182,693	16,674,038	17,179,837	17,700,503
Customer Service & Info Expense		11,366,078	11,713,496	12,070,832	12,438,715	12,817,448	13,207,343	13,608,721	14,021,915	14,447,262	14,885,113
Administrative and General Expense		7,808,590	8,047,269	8,292,762	8,545,593	8,805,693	9,073,555	9,349,305	9,633,172	9,925,389	10,226,197
SF Transmission O&M		687,194	704,374	721,983	740,033	758,534	777,497	796,934	816,858	837,279	858,211
Total Operating Costs		244,349,076	253,298,196	262,347,831	271,472,512	280,667,815	287,542,272	291,753,127	301,571,158	311,479,586	321,485,021
Depreciation - Plant and Equipment		15,434,363	15,919,753	16,916,245	17,943,824	19,010,086	20,116,525	20,985,177	21,796,330	22,640,321	23,516,845
Amortization of Capitalized Development Costs		1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000
Interest on Debt		26,619,559	27,447,785	28,278,885	29,113,504	29,951,832	30,794,071	31,661,395	32,561,590	33,495,803	34,465,350
Total Revenue Requirements	$1,794,013,248	$287,552,998	$297,815,734	$308,692,962	$319,679,841	$330,779,734	$339,602,868	$345,549,699	$357,079,078	$368,765,710	$380,617,215
PG&E Costs											
Distribution O&M Expense		$23,892,372	$24,622,672	$25,373,821	$26,147,139	$26,943,264	$27,762,853	$28,606,583	$29,475,146	$30,369,259	$31,289,656
System Power, Transmission & CTC		183,431,000	190,537,000	197,695,000	204,876,000	212,076,000	216,912,000	219,042,000	226,694,000	234,377,000	242,091,000
Franchise Fees and Property Tax		6,489,409	6,672,675	6,857,131	7,042,695	7,229,391	7,405,371	7,568,977	7,761,409	7,955,273	8,155,515
Customer Accounts Expense		13,515,873	13,929,002	14,353,926	14,791,930	15,241,757	15,705,397	16,182,693	16,674,038	17,179,837	17,700,503
Customer Service & Info Expense		11,366,078	11,713,496	12,070,832	12,438,715	12,817,448	13,207,343	13,608,721	14,021,915	14,447,262	14,885,113
Administrative and General Expense		8,291,635	8,545,079	8,805,758	9,074,223	9,350,420	9,634,851	9,927,659	10,229,087	10,539,381	10,858,796
Total Operating Costs		246,986,367	256,019,924	265,156,468	274,370,702	283,658,280	290,627,815	294,936,633	304,855,595	314,868,012	324,980,583
Depreciation		25,609,351	26,482,476	27,375,319	28,288,346	29,222,036	30,176,878	31,153,375	32,152,043	33,173,410	33,365,707
Return and Income Tax		65,297,381	67,001,670	68,713,327	70,432,887	72,160,907	73,897,959	75,644,635	77,401,544	79,169,317	81,064,346
Total Revenue Requirements	$2,092,476,425	$337,893,099	$349,504,071	$361,245,114	$373,091,936	$385,041,223	$394,702,651	$401,734,643	$414,409,182	$427,210,739	$439,410,636
Annual Revenue Requirement Difference Municipal versus PG&E	($298,463,177)	(50,340,101)	(51,688,337)	(52,552,152)	(53,412,095)	(54,261,489)	(55,099,783)	(56,184,944)	(57,330,104)	(58,445,029)	(58,793,421)

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	Net Present Value @12.5%	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Municipal Costs											
Distribution O&M Expense		$28,405,535	$29,268,003	$30,156,657	$31,072,294	$32,015,732	$32,987,815	$33,989,413	$35,021,422	$36,084,766	$37,180,396
System Power, Transmission & CTC		250,497,000	258,941,000	268,077,000	276,591,000	285,905,596	295,533,873	305,486,397	315,774,086	326,408,228	337,400,490
Franchise Fees and Property Tax		8,364,149	8,576,988	8,797,398	9,018,910	9,248,738	9,484,553	9,726,514	9,974,785	10,229,536	10,490,940
Customer Accounts Expense		18,237,937	18,791,690	19,362,256	19,950,146	20,555,885	21,180,017	21,823,098	22,485,706	23,168,432	23,871,887
Customer Service & Info Expense		15,337,065	15,802,739	16,282,552	16,776,934	17,286,326	17,811,185	18,351,980	18,909,195	19,483,329	20,074,895
Administrative and General Expense		10,536,691	10,856,613	11,186,249	11,525,893	11,875,850	12,236,433	12,607,964	12,990,775	13,385,210	13,791,620
SF Transmission O&M		879,666	901,658	924,200	947,305	970,987	995,262	1,020,143	1,045,647	1,071,788	1,098,583
Total Operating Costs		332,258,044	343,138,690	354,786,312	365,882,481	377,859,114	390,229,137	403,005,510	416,201,617	429,831,289	443,908,811
Depreciation - Plant and Equipment		24,539,067	25,605,723	26,718,744	27,880,146	29,092,030	30,356,593	31,676,123	33,053,010	34,489,747	35,988,936
Amortization of Capitalized Development Costs		1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000
Interest on Debt		35,462,765	36,488,968	37,544,523	38,629,994	39,745,945	40,892,933	42,071,514	43,282,237	44,525,644	45,802,270
Total Revenue Requirements	$1,794,013,248	$393,409,876	$406,383,382	$420,199,579	$433,542,621	$447,847,089	$462,628,663	$477,903,147	$493,686,864	$509,996,681	$526,850,017
PG&E Costs											
Distribution O&M Expense		$32,239,694	$33,218,577	$34,227,181	$35,266,410	$36,337,193	$37,440,487	$38,577,280	$39,748,589	$40,955,463	$42,198,980
System Power, Transmission & CTC		250,497,000	258,941,000	268,077,000	276,591,000	285,905,596	295,533,873	305,486,397	315,774,086	326,408,228	337,400,490
Franchise Fees and Property Tax		8,364,149	8,576,988	8,797,398	9,018,910	9,248,738	9,484,553	9,726,514	9,974,785	10,229,536	10,490,940
Customer Accounts Expense		18,237,937	18,791,690	19,362,256	19,950,146	20,555,885	21,180,017	21,823,098	22,485,706	23,168,432	23,871,887
Customer Service & Info Expense		15,337,065	15,802,739	16,282,552	16,776,934	17,286,326	17,811,185	18,351,980	18,909,195	19,483,329	20,074,895
Administrative and General Expense		11,188,498	11,528,211	11,878,238	12,238,823	12,610,499	12,993,387	13,387,901	13,794,393	14,213,228	14,644,780
Total Operating Costs		335,864,343	346,859,204	358,624,626	369,842,293	381,944,236	394,443,502	407,353,171	420,686,756	434,458,216	448,681,972
Depreciation		34,262,442	35,183,277	36,128,860	37,099,856	38,096,949	39,120,840	40,172,249	41,251,916	42,360,599	43,499,080
Return and Income Tax		82,972,746	84,926,073	86,925,385	88,971,765	91,066,319	93,210,184	95,404,519	97,650,512	99,949,380	102,302,368
Total Revenue Requirements	$2,092,476,425	$453,099,531	$466,968,554	$481,678,871	$495,913,914	$511,107,505	$526,774,526	$542,929,939	$559,589,183	$576,768,196	$594,483,419
Annual Revenue Requirement Difference Municipal versus PG&E	($298,463,177)	(59,689,654)	(60,585,172)	(61,479,292)	(62,371,292)	(63,260,416)	(64,145,863)	(65,026,792)	(65,902,319)	(66,771,515)	(67,633,402)

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	Net Present Value @12.5%	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Municipal Costs											
Distribution O&M Expense		$38,309,292	$39,472,465	$40,670,954	$41,905,833	$43,178,206	$44,489,211	$45,840,023	$47,231,848	$48,665,933	$50,143,561
System Power, Transmission & CTC		348,762,931	360,508,019	372,648,640	385,198,113	398,170,208	411,579,156	425,439,670	439,766,957	454,576,735	469,885,253
Franchise Fees and Property Tax		10,759,176	11,034,425	11,316,877	11,606,725	11,904,168	12,209,410	12,522,661	12,844,136	13,174,058	13,512,654
Customer Accounts Expense		24,596,702	25,343,523	26,113,020	26,905,881	27,722,815	28,564,554	29,431,850	30,325,480	31,246,242	32,194,961
Customer Service & Info Expense		20,684,422	21,312,456	21,959,559	22,626,310	23,313,305	24,021,159	24,750,506	25,501,997	26,276,306	27,074,125
Administrative and General Expense		14,210,371	14,641,835	15,086,401	15,544,464	16,016,435	16,502,737	17,003,804	17,520,085	18,052,042	18,600,150
SF Transmission O&M		1,126,047	1,154,199	1,183,054	1,212,630	1,242,946	1,274,019	1,305,870	1,338,516	1,371,979	1,406,279
Total Operating Costs		458,448,941	473,466,923	488,978,505	504,999,957	521,548,084	538,640,248	556,294,384	574,529,020	593,363,295	612,816,982
Depreciation - Plant and Equipment		37,553,291	39,185,644	40,888,953	42,666,300	44,520,904	46,456,124	48,475,463	50,582,578	52,781,284	55,075,563
Amortization of Capitalized Development Costs											
Interest on Debt		47,112,638	48,543,512	50,009,141	51,510,009	53,046,583	54,619,310	56,228,617	57,874,905	59,558,550	61,279,895
Total Revenue Requirements	$1,794,013,248	$543,114,870	$561,196,079	$579,876,599	$599,176,265	$619,115,571	$639,715,682	$660,998,464	$682,986,503	$705,703,129	$729,172,440
PG&E Costs											
Distribution O&M Expense		$43,480,254	$44,800,430	$46,160,691	$47,562,253	$49,006,370	$50,494,334	$52,027,477	$53,607,170	$55,234,827	$56,911,904
System Power, Transmission & CTC		348,762,931	360,508,019	372,648,640	385,198,113	398,170,208	411,579,156	425,439,670	439,766,957	454,576,735	469,885,253
Franchise Fees and Property Tax		10,759,176	11,034,425	11,316,877	11,606,725	11,904,168	12,209,410	12,522,661	12,844,136	13,174,058	13,512,654
Customer Accounts Expense		24,596,702	25,343,523	26,113,020	26,905,881	27,722,815	28,564,554	29,431,850	30,325,480	31,246,242	32,194,961
Customer Service & Info Expense		20,684,422	21,312,456	21,959,559	22,626,310	23,313,305	24,021,159	24,750,506	25,501,997	26,276,306	27,074,125
Administrative and General Expense		15,089,434	15,547,590	16,019,656	16,506,056	17,007,223	17,523,608	18,055,672	18,603,890	19,168,754	19,750,768
Total Operating Costs		463,372,919	478,546,444	494,218,444	510,405,339	527,124,091	544,392,223	562,227,836	580,649,630	599,676,922	619,329,665
Depreciation		44,668,158	45,868,656	47,101,419	48,367,313	49,667,230	51,002,083	52,372,811	53,780,379	55,225,776	56,710,020
Return and Income Tax		104,710,749	107,175,828	109,698,939	112,281,448	114,924,755	117,630,290	120,399,517	123,233,938	126,135,086	129,104,532
Total Revenue Requirements	$2,092,476,425	$612,751,825	$631,590,928	$651,018,801	$671,054,100	$691,716,075	$713,024,595	$735,000,165	$757,663,947	$781,037,784	$805,144,218
Annual Revenue Requirement Difference Municipal versus PG&E	($298,463,177)	(69,636,955)	(70,394,849)	(71,142,203)	(71,877,835)	(72,600,504)	(73,308,913)	(74,001,701)	(74,677,444)	(75,334,655)	(75,971,777)

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Table 4-5
Estimate of Revenue Requirements 2002 - 2011
Municipal Versus PG&E - Low Cost Case
Transfer Price - Net Income Method

	Net Present Value @12.5%	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Municipal Costs											
Distribution O&M Expense		$21,050,932	$21,694,380	$22,356,197	$23,037,547	$23,738,992	$24,461,110	$25,204,497	$25,969,766	$26,757,545	$27,568,482
System Power, Transmission & CTC		183,431,000	190,537,000	197,695,000	204,876,000	212,076,000	216,912,000	219,042,000	226,694,000	234,377,000	242,091,000
Franchise Fees and Property Tax		6,489,409	6,672,675	6,857,131	7,042,695	7,229,391	7,405,371	7,568,977	7,761,409	7,955,273	8,155,515
Customer Accounts Expense		13,515,873	13,929,002	14,353,926	14,791,930	15,241,757	15,705,397	16,182,693	16,674,038	17,179,837	17,700,503
Customer Service & Info Expense		11,366,078	11,713,496	12,070,832	12,438,715	12,817,448	13,207,343	13,608,721	14,021,915	14,447,262	14,885,113
Administrative and General Expense		7,808,590	8,047,269	8,292,762	8,545,593	8,805,693	9,073,555	9,349,305	9,633,172	9,925,389	10,226,197
SF Transmission O&M		687,194	704,374	721,983	740,033	758,534	777,497	796,934	816,858	837,279	858,211
Total Operating Costs		244,349,076	253,298,196	262,347,831	271,472,512	280,667,815	287,542,272	291,753,127	301,571,158	311,479,586	321,485,021
Depreciation - Plant and Equipment		24,826,418	25,311,808	26,308,301	27,335,880	28,402,142	29,508,581	30,377,233	31,188,386	32,032,377	32,908,901
Amortization of Capitalized Development Costs		1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000
Interest on Debt		39,626,912	39,750,734	39,877,431	40,007,645	40,141,569	40,279,404	40,442,323	40,638,114	40,867,924	41,133,066
Total Revenue Requirements	$1,904,180,432	$309,952,407	$319,510,739	$329,683,563	$339,966,038	$350,361,527	$358,480,257	$363,722,683	$374,547,658	$385,529,886	$396,676,987
PG&E Costs											
Distribution O&M Expense		$23,892,372	$24,622,672	$25,373,821	$26,147,139	$26,943,264	$27,762,853	$28,606,583	$29,475,146	$30,369,259	$31,289,656
System Power, Transmission & CTC		183,431,000	190,537,000	197,695,000	204,876,000	212,076,000	216,912,000	219,042,000	226,694,000	234,377,000	242,091,000
Franchise Fees and Property Tax		6,489,409	6,672,675	6,857,131	7,042,695	7,229,391	7,405,371	7,568,977	7,761,409	7,955,273	8,155,515
Customer Accounts Expense		13,515,873	13,929,002	14,353,926	14,791,930	15,241,757	15,705,397	16,182,693	16,674,038	17,179,837	17,700,503
Customer Service & Info Expense		11,366,078	11,713,496	12,070,832	12,438,715	12,817,448	13,207,343	13,608,721	14,021,915	14,447,262	14,885,113
Administrative and General Expense		8,291,635	8,545,079	8,805,758	9,074,223	9,350,420	9,634,851	9,927,659	10,229,087	10,539,381	10,858,796
Total Operating Costs		246,986,367	256,019,924	265,156,468	274,370,702	283,658,280	290,627,815	294,936,633	304,855,595	314,868,012	324,980,583
Depreciation		25,609,351	26,482,476	27,375,319	28,288,346	29,222,036	30,176,878	31,153,375	32,152,043	33,173,410	33,365,707
Return and Income Tax		65,297,381	67,001,670	68,713,327	70,432,887	72,160,907	73,897,959	75,644,635	77,401,544	79,169,317	81,064,346
Total Revenue Requirements	$2,092,476,425	$337,893,099	$349,504,071	$361,245,114	$373,091,936	$385,041,223	$394,702,651	$401,734,643	$414,409,182	$427,210,739	$439,410,636
Annual Revenue Requirement Difference Municipal versus PG&E	($188,295,993)	(27,940,692)	(29,993,332)	(31,561,551)	(33,125,898)	(34,679,696)	(36,222,394)	(38,011,960)	(39,861,524)	(41,680,853)	(42,733,649)

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	Net Present Value @12.5%	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Municipal Costs											
Distribution O&M Expense		$28,405,535	$29,268,003	$30,156,657	$31,072,294	$32,015,732	$32,987,815	$33,989,413	$35,021,422	$36,084,766	$37,180,396
System Power, Transmission & CTC		250,497,000	258,941,000	268,077,000	276,591,000	285,905,596	295,533,873	305,486,397	315,774,086	326,408,228	337,400,490
Franchise Fees and Property Tax		8,364,149	8,576,988	8,797,398	9,018,910	9,248,738	9,484,553	9,726,514	9,974,785	10,229,536	10,490,940
Customer Accounts Expense		18,237,937	18,791,690	19,362,256	19,950,146	20,555,885	21,180,017	21,823,098	22,485,706	23,168,432	23,871,887
Customer Service & Info Expense		15,337,065	15,802,739	16,282,552	16,776,934	17,286,326	17,811,185	18,351,980	18,909,195	19,483,329	20,074,895
Administrative and General Expense		10,536,691	10,856,613	11,186,249	11,525,893	11,875,850	12,236,433	12,607,964	12,990,775	13,385,210	13,791,620
SF Transmission O&M		879,666	901,658	924,200	947,305	970,987	995,262	1,020,143	1,045,647	1,071,788	1,098,583
Total Operating Costs		332,258,044	343,138,690	354,786,312	365,882,481	377,859,114	390,229,137	403,005,510	416,201,617	429,831,289	443,908,811
Depreciation - Plant and Equipment		33,931,123	34,997,779	36,110,800	37,272,201	38,484,086	39,748,649	41,068,179	42,445,066	43,881,803	45,380,991
Amortization of Capitalzed Development Costs		1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000
Interest on Debt		41,426,077	41,747,876	42,099,026	42,480,094	42,891,640	43,334,224	43,808,401	44,314,720	44,853,723	45,425,944
Total Revenue Requirements	$1,904,180,432	$408,765,244	$421,034,345	$434,146,138	$446,784,776	$460,384,840	$474,462,010	$489,032,089	$504,111,402	$519,716,815	$535,865,747
PG&E Costs		2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
Distribution O&M Expense		$32,239,694	$33,218,577	$34,227,181	$35,266,410	$36,337,193	$37,440,487	$38,577,280	$39,748,589	$40,955,463	$42,198,980
System Power, Transmission & CTC		250,497,000	258,941,000	268,077,000	276,591,000	285,905,596	295,533,873	305,486,397	315,774,086	326,408,228	337,400,490
Franchise Fees and Property Tax		8,364,149	8,576,988	8,797,398	9,018,910	9,248,738	9,484,553	9,726,514	9,974,785	10,229,536	10,490,940
Customer Accounts Expense		18,237,937	18,791,690	19,362,256	19,950,146	20,555,885	21,180,017	21,823,098	22,485,706	23,168,432	23,871,887
Customer Service & Info Expense		15,337,065	15,802,739	16,282,552	16,776,934	17,286,326	17,811,185	18,351,980	18,909,195	19,483,329	20,074,895
Administrative and General Expense		11,188,498	11,528,211	11,878,238	12,238,893	12,610,499	12,993,387	13,387,901	13,794,393	14,213,228	14,644,780
Total Operating Costs		335,864,343	346,859,204	358,624,626	369,842,293	381,944,236	394,443,502	407,353,171	420,686,756	434,458,216	448,681,972
Depreciation		34,262,442	35,183,277	36,128,860	37,099,856	38,096,949	39,120,840	40,172,249	41,251,916	42,360,599	43,499,080
Return and Income Tax		82,972,746	84,926,073	86,925,385	88,971,765	91,066,319	93,210,184	95,404,519	97,650,512	99,949,380	102,302,368
Total Revenue Requirements	$2,092,476,425	$453,099,531	$466,968,554	$481,678,871	$495,913,914	$511,107,505	$526,774,526	$542,929,939	$559,589,183	$576,768,196	$594,483,419
Annual Revenue Requirement Difference											
Municipal versus PG&E	($188,295,993)	(44,334,287)	(45,934,209)	(47,532,732)	(49,129,137)	(50,722,665)	(52,312,516)	(53,897,849)	(55,477,781)	(57,051,381)	(58,617,672)

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	Net Present Value @12.5%	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Municipal Costs											
Distribution O&M Expense		$38,309,292	$39,472,465	$40,670,954	$41,905,833	$43,178,206	$44,489,211	$45,840,023	$47,231,848	$48,665,933	$50,143,561
System Power, Transmission & CTC		348,762,931	360,508,019	372,648,640	385,198,113	398,170,208	411,579,156	425,439,670	439,766,957	454,576,735	469,885,253
Franchise Fees and Property Tax		10,759,176	11,034,425	11,316,877	11,606,725	11,904,168	12,209,410	12,522,661	12,844,136	13,174,058	13,512,654
Customer Accounts Expense		24,596,702	25,343,523	26,113,020	26,905,881	27,722,815	28,564,554	29,431,850	30,325,480	31,246,242	32,194,961
Customer Service & Info Expense		20,684,422	21,312,456	21,959,559	22,626,310	23,313,305	24,021,159	24,750,506	25,501,997	26,276,306	27,074,125
Administrative and General Expense		14,210,371	14,641,835	15,086,401	15,544,464	16,016,435	16,502,737	17,003,804	17,520,085	18,052,042	18,600,150
SF Transmission O&M		1,126,047	1,154,199	1,183,054	1,212,630	1,242,946	1,274,019	1,305,870	1,338,516	1,371,979	1,406,279
Total Operating Costs		458,448,941	473,466,923	488,978,505	504,999,957	521,548,084	538,640,248	556,294,384	574,529,020	593,363,295	612,816,982
Depreciation - Plant and Equipment		37,553,291	39,185,644	40,888,953	42,666,300	44,520,904	46,456,124	48,475,463	50,582,578	52,781,284	55,075,563
Amortization of Capitalzed Development Costs						0	0				
Interest on Debt		46,736,313	48,167,186	49,632,815	51,133,683	52,670,257	54,242,985	55,852,292	57,498,580	59,182,224	60,903,569
Total Revenue Requirements	$1,904,180,432	$542,738,544	$560,819,754	$579,500,273	$598,799,940	$618,739,245	$639,339,356	$660,622,138	$682,610,177	$705,326,803	$728,796,115
PG&E Costs		2022	2023	2024	2025	2026	2027	2028	2029	2030	2031
Distribution O&M Expense		$43,480,254	$44,800,430	$46,160,691	$47,562,253	$49,006,370	$50,494,334	$52,027,477	$53,607,170	$55,234,827	$56,911,904
System Power, Transmission & CTC		348,762,931	360,508,019	372,648,640	385,198,113	398,170,208	411,579,156	425,439,670	439,766,957	454,576,735	469,885,253
Franchise Fees and Property Tax		10,759,176	11,034,425	11,316,877	11,606,725	11,904,168	12,209,410	12,522,661	12,844,136	13,174,058	13,512,654
Customer Accounts Expense		24,596,702	25,343,523	26,113,020	26,905,881	27,722,815	28,564,554	29,431,850	30,325,480	31,246,242	32,194,961
Customer Service & Info Expense		20,684,422	21,312,456	21,959,559	22,626,310	23,313,305	24,021,159	24,750,506	25,501,997	26,276,306	27,074,125
Administrative and General Expense		15,089,434	15,547,590	16,019,656	16,506,056	17,007,223	17,523,608	18,055,672	18,603,890	19,168,754	19,750,768
Total Operating Costs		463,372,919	478,546,444	494,218,444	510,405,339	527,124,091	544,392,223	562,227,836	580,649,630	599,676,922	619,329,665
Depreciation		44,668,158	45,868,656	47,101,419	48,367,313	49,667,230	51,002,083	52,372,811	53,780,379	55,225,776	56,710,020
Return and Income Tax		104,710,749	107,175,828	109,698,939	112,281,448	114,924,755	117,630,290	120,399,517	123,233,938	126,135,086	129,104,532
Total Revenue Requirements	$2,092,476,425	$612,751,825	$631,590,928	$651,018,801	$671,054,100	$691,716,075	$713,024,595	$735,000,165	$757,663,947	$781,037,784	$805,144,218
Annual Revenue Requirement Difference											
Municipal versus PG&E	($188,295,993)	(70,013,281)	(70,771,174)	(71,518,528)	(72,254,160)	(72,976,830)	(73,685,239)	(74,378,026)	(75,053,770)	(75,710,981)	(76,348,103)

Annual Amort. of Development Costs	1 2002	2 2003	3 2004	4 2005	5 2006	6 2007	7 2008	8 2009	9 2010	10 2011
Beg of Year Balance	$23,000,000	$21,850,000	$20,700,000	$19,550,000	$18,400,000	$17,250,000	$16,100,000	$14,950,000	$13,800,000	$12,650,000
Amortization	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000
End of Year Balance	21,850,000	20,700,000	19,550,000	18,400,000	17,250,000	16,100,000	14,950,000	13,800,000	12,650,000	11,500,000

11	12	13	14	15	16	17	18	19	20
2012	2013	2014	2015	2016	2017	2018	2019	2020	2021
$11,500,000	$10,350,000	$9,200,000	$8,050,000	$6,900,000	$5,750,000	$4,600,000	$3,450,000	$2,300,000	$1,150,000
1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000	1,150,000
10,350,000	9,200,000	8,050,000	6,900,000	5,750,000	4,600,000	3,450,000	2,300,000	1,150,000	0

Workpapers

Chapter 5

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Workpapers

CAPITALIZED DEVELOPMENT COSTS

July 1 1997 to June 30, 199 Feasibility Study 6 py * $70 hr =	$1,000,000
June 1, 1999 Referendum: 1. Vote By BOS (Legal Opinions)	100,000
2. Gen Plane	150,000
3. Voter Education	250,000
	500,000
Jan 1, 2000 BOS Issues Resolution	100,000
Admin for 1st half of year	200,000
Admin 2 nd half of year	1,700,000
Condemnation Lawsuit Filed July 1, 2000, So legal full year	2,000,000
	4,000,000
Legal for all of 2001	3,000,000
Admin for 1st half of year ($6.8/4)	1,700,000
Admin for 2nd half ($6.8/2)	3,400,000
O&M and CB and CI training and staffing process ($38/4)	9,500,000
	17,600,000
Total Capitalized Development Cost	23,100,000
	23,000,000

Responses to Comments

of CCSF/PUC/HHWP Staff

& Technical Review Committee

on First Draft of Report

The Technical Review Committee (TRC) assembled by The City and County of San Francisco for this project prepared a memorandum of comments on ETAG's Draft Preliminary Feasibility Study. Working from a computer file of that memorandum, ETAG has provided answers to those comments. This document includes each comment as taken from the TRC memorandum, followed by our response to the item (*italicized*, beginning with "***Response:***").

MEMORANDUM

TO: ETAG - Ron Knecht

FROM: HHWP - Laurie Park

SUBJECT: Technical Review Committee Comments on ETAG's First Draft of the Preliminary Municipalization Feasibility Study; Meeting held on Wednesday, October 16, 1996

DATE: October 17, 1996

This memorandum reports the comments of the October 16th meeting of the Technical Review Committee (TRC). Seven out of the eight members of the TRC were present:

Robert Lehman, San Franciscans for Tax Justice
Sheryl Carter, Natural Resource Defense Council
Eva Bruce, CCSF Controller's Office
Eugene Coyle, TURN
Joel Ventresca, San Franciscans for Public Power
Wally McOuat, Hansen, McOuat & Hamrin, Inc.
Laurie Park, Chair - Acting for Larry Klein, General Manager, Hetch Hetchy

Mr. Carl Blumstein, U.C. Energy Institute, could not be present. Mr. Tom Habashi, City of Palo Alto, has had to drop out due to time constraints. Shirley Hoaglin - Project Administrator was present. Mr. Tim Dayonot, the Manager of Government Affairs for the SFPUC, acted as Meeting Facilitator by request of Chair - Laurie Park.

COMMENTS RELATED TO REPORT STRUCTURE AND CONTENT

1. Report Structure. The report is difficult to read and absorb, and the conclusions and recommendations difficult to identify. Structural modifications to the report are urged to

facilitate comprehension. In particular, the contractor should be cognizant of the audience and present the study findings in such a way that it would be useful to the City's decision makers.

Response: We have rewritten the report and added a 10-page executive summary concisely laying out overall conclusions and recommendations.

The following structural and format changes are recommended:

a. Add a Table of Contents with page numbers referenced.

Response: We have done so.

b. Page numbers should notate Section # - page # (e.g. "II-1") and be easily identified.

Response: We have done so.

c. Include glossary at end which defines terms and acronyms used in this study.

Response: We have added an acronyms list in this document. Terms and acronyms are defined in our report when first used.

d. Terms should be used consistently throughout the study.

Response: We have done so.

e. Add a Table of Assumptions which clearly delineates: which assumptions depend on a valuation or other methodology and are verifiable by calculation, which assumptions are speculative in nature and depend on an outcome of the electric industry restructure which has not yet been determined, what would be the likely range of values produced by each, and how each assumption is employed in the study.

Response: We have created a table of key assumptions in chapter 4 (Figure 4-1) which lays out key assumptions for the BAU case (continued service from PG&E) and for the muncipalization cases presented in the report. Valuation results are presented in detail in chapter 2 and are "verifiable by calculation". For the range of valuations, we present the economic results in chapter 4. We also present the results of a "what if " sensitivity for two forecast ("speculative") variables that could have a material impact on the study results in section 4.B.6. In addition, we changed the presentation so that the valuation assumption impacts on each case study are delineated from operating cost assumptions. Finally, we added a cents-per-kWh comparisons for selected forecasted years in chapter 4 so that any reader of this report, no matter how little

he or she understands the electric utility industry, can easily determine what is and what is not important to the overall study results.

f. Add a section at the beginning stating the purpose of the study (study objectives).

Response: *We have done so in the Executive Summary.*

g. Some charts are too small to read; each chart should be reviewed and enhanced so that an average reader not versed in the electric industry can understand it.

Response: *We have reduced the number of charts in Chapter 1 to eliminate redundant presentation and have simplified the remaining charts. We have also revised the charts for readability and rewritten the text. In other chapters, we have substituted simple, results-oriented charts for the complex numerical tables included in the original draft.*

h. The overviews at the beginning of each chapter should be concise and directly support/be relevant to the conclusions provided at the end of each chapter.

Response: *We have assured this in the revised report.*

I. More visual representations of concepts, relative values, etc. (i.e. graphics) should be employed to facilitate understanding.

Response: *See the response to item g above.*

j. Each table used should be clearly referenced in the text.

Response: *We have done so.*

k. Tables not used/not relevant to the study conclusions should either be eliminated or removed from the body of the report.

Response: We have done so.

l. Sources of all data must be indicated on the table or chart, or provided in a footnote.

Response: *We have done so.*

m. A summary table illustrating all of the relative costs vs. benefits of each case presented should be provided.

Response: *We have done so. See especially Tables 4-1, -2 and -3. (Table 4-3 is also Table ES-1.)*

n. The use of "pessimistic", "optimistic" and "base" cases in Chapters 2 and 3, but for different purposes (acquisition of distribution system and operating costs respectively) is confusing.

Response: We have deleted this usage in the revised report.

o. Appendix IIIA discusses matters directly relevant to the study and should be integrated into the body of the text.

Response: We have done so to the extent that material has been kept.

p. Add a breakdown of the build-up of costs by component in $/kWhr for each of the following: transmission, distribution, energy, customer costs (metering, customer billing & accounting), other (cost of capital, rate of return, etc.) -- based on current vs. project (year 2002) rates, and with and without the effects of the electric restructure.

Response: We have done so; see especially Tables 4-1 and -2.

q. Need more and better sensitivity analyses, and need to show the range of impact on assumptions (e.g. with tax-free bonds and without).

Response: We believe that we have identified and quantified the "important" key variables that can have a material impact on the study results; the valuation or "price to be paid" for the SF distribution system, the role of income taxes and PG&E profits, distribution O&M and the allocation of SF reliability costs. As for valuation, we have calculated the economic results for each valuation case (chapter 4). We have tested the sensitivity of distribution O&M assumptions and the reliability cost allocation assumption in the "what if" scenarios now included in chapter 4. As to the specific item used as an example in the TRC comments, a sensitivity assuming tax free bonds, it is our opinion, that the IRS rules, since the passage of the Tax Reform Act of 1986 specifically does not allow the use of tax free municipal bonds to acquire an operating electric utility system. Therefore, where either the impact of a change in an assumption is not material to the overall study results or where there is no foundation for making a different assumption we have not done so.

2. Report Errors, Bias and/or Lack of Support. Three Committee members felt that the study presentation appeared biased towards non-acquisition of distribution facilities. Other Committee members felt that this perception may have been attributable to failure to properly document all assumptions and sources.

Examples:

a. Chapter 1 does not reflect recent academic literature on municipals.

Response: *This item was outside the scope of work for the project. However, we reviewed the materials to which the commenter referred (one article), as well as to some other items in the revised report. As reported at pages 3-12 and 3-14 of the revised report, we find that the article is invalid in its methods; the particular error in method leads directly to at least part of the otherwise unexplained muni benefit ascribed to better muni performance, and the error invalidates all parts of the paper. Moreover, even if the paper were valid, one paper based on characteristics of existing munis does not tell the story for new municipalizations and does not successfully contravene a direct assessment for a particular city.*

b. Chapter 1 asserts that tax benefits are the primary reason municipals have lower prices.

Response: *It does so because the conclusion is true, as shown by the data. The only suggestion to the contrary is made in the paper discussed in item 2a above and other partisan sources relying on it. No one has presented any valid evidence to the contrary.*

c. On p. 9, the assertion is made that: "as a general rule, IOUs are cost-based". What is the implication of this statement?

Response: *This question is vague to the extent it requests any answer beyond what the rest of the cited sentence says. In any event, the cited material has been deleted.*

d. The references to municipals charging higher rates to large energy users to subsidize rates for residential customers seems an effort to convey to business community that they will subsidize small customers, a statement that is not based on fact. [One member of the TRC did not agree with this comment, indicating that this subsidy is widespread.]

Response: *As reported in our draft, muni industrial rates are higher on average than IOUs' industrial rates. In any event, this material has been removed from the revised report.*

e. On p.24 , the discussion about income tax benefits is not balanced.

Response: *The cited discussion is accurate, balanced and fair. Labeling it "unbalanced" is not helpful without saying what's wrong with it (e.g., mis-statements of fact, specific omissions, etc.).*

f. The discussion about IOUs "supporting" Qualifying Facilities ("QFs") suggests that IOUs support renewables more than municipals which is misleading because IOUs buy from QFs because they have to. This incorrectly portrays IOUs as being better than public power entities for the environment.

Response: *This criticism seems to misunderstand the BAU alternative, which includes both the IOU and its regulation. The claim that IOUs support QFs only "because they have to" is*

arguable We neither infer not intended the interpretation re: the environment suggested in the comment. In any event, this subjective claim is irrelevant here, because even if true, the BAU alternative inherently includes the regulation that, according to this complaint, is the reason IOUs have done as much as they have in power contracting.

g. Only one reference to the American Public Power Association appears in this study (on p.20), and it is not even referred to correctly.

Response: *This criticism fails to point out that APPA's opposite (the Edison Electric Institute) was not cited even once, as APPA was. In the revised report, APPA's material is reviewed and cited extensively and correctly.*

h. There is no indication that the six public power cities referred to in Chapter 1 were ever consulted or had an opportunity to review this write-up; nor that APPA was used in any meaningful way. Both public power and IOUs should be consulted to ensure accuracy of conclusions.

Response: *APPA was consulted and materials received from it were used, even though not always cited in the draft (as they are in the revised report). The munis were provided an opportunity to comment on the analyses before they were used in the revised report, and no criticism was received. Moreover, this criticism is simply wrong in stating that there is no indication of contact with the six munis, for Table 1-5 in the Appendix expressly documents our survey of California munis with names and telephone numbers for contact persons.*

I. Whenever PG&E is mentioned, it's in a positive light. Whenever public power is mentioned, it's mentioned in a negative light. [One member of the TRC did not agree with this comment.]

Response: *As reflected in the one member's dissent, this criticism is simply wrong. Examples were given at the October TRC meeting by ETAG. See also, especially, response to item l below.*

j. What evidence is there to support the comment that public power systems are no more or less efficient than IOUs?

Response: *See the six city-pair data and discussion in section 1.B.*

k. What academic context is there to adjust the table of comparative costs of electricity of IOUs vs. municipals on p.12?

Response: *There is a factual and sound analytic basis, as explained in the cited text and the revised report -- and thus, regardless of what some "academic" studies may purport to show, this adjustment is entirely proper and merited as a factual and sound analytic matter.*

l. Why does the study accept PG&E sources of information without critical analysis? E.g. cite of conversation with PG&E person naming figure of $2 billion without challenge or analysis. A number of such key assumptions were made that are attributable to PG&E representations, and ETAG just seems to accept them. See also item 2a above.

Response: *The stated predicate of this question is false. All PG&E data were, in fact, subject to full scrutiny appropriate to each. As to the cited item, the criticism ignores the stated fact that this datum was not available from any other source. It also misunderstands the import of this item. We recognize that PG&E has incentives to over-state the value cited because it is used in ratemaking in a way that over-statement will increase its revneue --, but we also recognize that over-statement of it favors the muni option in our analysis (contrary to what the criticism suggests, especially as it was stated at the TRC meeting). Hence, because it was the only such estimate available and because it comes from PG&E and errs in a manner disfavoring the PG&E option here, it is sound reliance.*

m. On p.130, there is a discussion that if the City pursued municipalization, there would be another $18.5 million in costs, but there is no backup for any of the assumptions used to develop this estimate.

Response: *Back-up is provided in the revised report on page 5-12.*

n. On p.30, footnote 2, state that the Palm Springs effort indicates that "muni-lite" is "dead"; feel that is overstated.

Response: *This item has been edited out of the revised report.*

o. On p.34 re: area cost averaging, state that SF's distribution system is worth more than other PG&E service areas due to density (lower cost per customer); but don't address the fact that City customers could leave the PG&E system for their energy needs. Also, don't address the future possibility for generation to be owned by customers, such as fuel cells for hospitals, etc.

Response: *This criticism is wrong. As the draft and revised reports both note, City customers (and others) bypassing PG&E's electricity supply would still have to pay the CTC. As for self-generation uses (fuel cells), our load forecasts include those currently on line and reasonably expected; since PG&E's rates, as we report, are already among the highest, and since they are headed down even before AB 1890 and more since it, these forecasts over-state self-gen if they err on it. The fact that customers have a theoretical self-gen option is irrelevant to valuation if they are not going to use it at the expected rate levels incorporated into the valuation.*

p. On p.109, talk about PG&E's costs being low due to cutbacks in staffing. PG&E has brought back some staff for system reliability reasons and this point should be

addressed; also, the impact of these staffing changes on system outages should be addressed.

Response: We referred to the net current versus prior levels of staffing, so that reflects the fact that call-backs (which are temporary, as the comment fails to note) have been greatly exceeded by cuts. Impacts on outages, if any, are not currently known or probably even knowable yet. Further, adjustments that seem to be implied in these comments would simply increase the cost of the muni option.

q. On p.109, talk about the inefficiency of the municipal railway; is anti-government rhetoric. [One member of the TRC did not agree with this comment.]

Response: It is no such thing; it's a fact, and the dissent is again correct. In addition, to be fair, if we were to eliminate all reference to problems in public-sector provision, we would also have to eliminate all reference to regulated-IOU provision, including references to PG&E's very high rates.

r. On p.112, state that substantial public benefit levels are already built into the municipalization scenario if the City provides DSM "as efficiently as PG&E". In fact, PG&E has been inefficient in the management of its DSM programs (cost per kWhr is high). [One member of the TRC did not agree with this comment and stated that PG&E's cost for DSM is actually low -- approximately 2 to 2.5 cents per kWhr on average.]

Response: Again, the dissent appears to be correct. However, this matter has been removed from the revised report as not relevant to the muni v. BAU choice.

s. On p.112, says "... only LADWP among the California municipal electric utilities makes [large investments in DSM comparable to IOUs] ...". Again, the point that IOUs invest in DSM because they have to has been overlooked. In addition, one member of the TRC pointed out that in fact, LADWP makes almost no investments in DSM.

Response: The one member appears to be correct. The import of this comment is wrong; see item 2f. However, this material has been removed from the revised report as not probative to the muni/BAU choice.

t. On p.123, property and payroll taxes are a "wash" and don't really depend on whether PG&E moves out of the City. Also, if the $7.6 million is for office buildings, we wouldn't lose that either.

Response: This comment mis-states our reported results. We did not say that property taxes have anything to do with PG&E relocating its corporate offices outside SF; they don't and we

made no such usage in our calculations. Payroll taxes do depend on such a decision, because a few thousand corporate-office jobs (i.e., not those associated only with SF electric operations, which jobs would move to CCSF) would leave with PG&E, if it left (which we do not assume).

3. Presentation of Scenarios. There were a number of issues raised with respect to how the various methodologies and assumptions were employed, and a need to enhance readability and understanding of the study results.

   a. Need to clearly spell out the actual value formula presented for each scenario with a glossary included that defines all terms. Wherever an analysis can be connected to some kind of statistical analysis, it would be helpful.

Response: We have done so. See also item 1c here. The suggestion of connection to a statistical analysis is vague and confusing, because statistical analyses are, appropriately, not much used in this work. We have used the appropriate range of other engineering, economic, legal, public-policy and accounting tools. The only sophisticated statistical analysis that has arisen in this work is the article discussed in item 2a above, which we found to be completely undermined by a data-specification error for a key data vector -- and which invalidates the results of the analysis, especially the primary results. We asked the author of this study about his reasons for this specification, and he had no explanation off the top of his head (which is reasonable, given that the work is more than three years old). If he reports a sound basis, we will modify our position on this study, but we do not expect that to happen because we recognize a plain error in an area of our expertise.

   b. The capitalization valuation approach was rejected in a case wherein SMUD acquired some PG&E properties [Superior Court, State of California, In and for the County of Sacramento, Case #322251 - 1989]. The valuation methodology employed by Ron Knecht in testimony on behalf of PG&E resulted in a valuation of $36 million; the parties eventually settled on $11-13 million. Why was this discredited capitalization valuation approach used?

Response: This comment errs in many regards. Fundamentally, because the SMUD-Folsom case was settled, nothing was rejected; the case didn't even go to trial, so nothing could have been rejected or discredited. The notion that a case settlement, even if the other erroneous items cited here were gotten right, could successfully by itself counteract the economic and legal analysis presented in our study -- such a notion is a basic error. The comment does not even attempt to address our analysis to show it errs; instead, it mischaracterizes one settled case and leaps to the assertion that its characterization of that case proves that our analysis is erroneous. The figures cited are wrong, too. Finally, the actual settlement was based on a replacement-cost formula, so the implication of this criticism is that replacement-cost formulas should be used in this work as the base case (even though the income-capitalization analysis complained about yields lower figures by far here).

c. The study spent 4 pages discussing the capitalization valuation approach and why it wasn't any good and then doesn't use it for any reason. Again, the study delves into matters that are not relevant.

Response: This statement is wrong. The draft and revised reports do not state that the income-valuation approach "wasn't any good"; quite to the contrary, they state that, while other methods have merit, this one is probably the best single method. Further, the report shows clearly that the method was used to calculate the $505-million valuation. We do not find the method and its result at all "not relevant" -- but highly relevant.

d. With respect to "Replacement Cost Less Depreciation" (RCLD) estimates, how were these estimates arrived at? What were the assumptions underlying these calculations and choices of depreciation methodologies? What kinds of margins of error would there be in both of those components?

Response: The method and assumptions used to arrive at RCLD is laid out in section 2.C. The basis for the depreciation methods are laid out in section 2.A. We have clearly stated that the RCLD estimates are subject to change based on the results of a detailed inventory of SF distribution plant and equipment. We have pointed out at several places in the report that valuation, i.e, the "price", is the key risk factor in the overall economic evaluation of municipalization. We have used an independent RCLD valuation from the State Board of Equalization as a check on the reasonableness of our study results. We have also pointed out that a court, in the condemnation proceeding, will ultimately adopt the method of depreciation that will "actually be used". The workpapers that support our calculations of RCLD as well as book value and the income method cover more than 100 pages of detailed computer print-outs.

e. Appendix II-A discusses several different municipalizations, but none of the condemnations indicated what kind of valuation method was used. Only the ones that were voluntary had any footnotes as to the valuation methods used. Need to fill that information out, plus add experience outside of California that substantiate legal precedents re: valuations and what legal sources were used that explain why the parties settled on the particular methodology eventually employed.

Response: Appendix II-A reports all the data available, as discussed in the text citing it. As discussed, because most condemnation cases settle, there is no stated basis for many of them. Because valuation is a matter of state law, out-of-state cases are not controlling, except the few federal appellate cases which we incorporated into our analysis. California law is rich enough with precedent and consistent enough with the mainstream on these matters that cases from other states would be gratuitous in our text (especially in light of some comments in this series about allegedly irrelevant matters).

f. Want to see net cash flow presentation on various options.

Response: *A "sources and used of funds" projection is presented in section 4.B.7. This forecast contains estimates of internal cash generation and annual capital requirements. The accompanying text, in section 4.B.7, describes the results for the two other cases not graphically presented. The only variable that will materially impact the level of new bond issues and internal cash flow is the "price" paid for the SF distribution system and no other operating assumption will alter the cash flow results. Only if we were to assume that electric were set below or above the cost of service would there be a material change in the results presented in section 4.B.7. Since we have no basis for such an assumption we did test the sensitivity of such an assumption.*

g. Why is the "optimistic" case the most favorable, and the "pessimistic" case not the most unfavorable? The bases should be directly comparable; i.e. if the "optimistic" case is the most favorable, the "pessimistic" case should be the most unfavorable.

Response: *As stated in the Draft, we characterized the cases, merely for convenience, on the basis of the effects of their assumptions and results for the prospects for municipalization. In any event, the revised report simplifies and makes the case structure much clearer, obviating this problem.*

h. The probabilities employed in the study appear to have been applied inconsistently (refer pp.117-123). References as to which constitutes the "most likely" case appear inconsistent.

Response: *See item 3g above.*

4. Hetch Hetchy Energy.

a. On p. 51, it states that 1994 energy sales to SF residential customers totaled 1.2 million MWH. The most recent annual report from APPA indicated that Hetch Hetchy generation totaled 1.6 million MWH [APPA "Public Power", Jan-Feb 1996 p.69] -- enough to supply SF residential consumption.

1) One TRC member felt that the study says none of Hetch Hetchy's generation should benefit SF residential users.
2) Other TRC members felt that the study only indicates that Hetch Hetchy generation is currently contractually committed to other parties.

Response: *In the revised report, we have attempted to simplify and clarify the impact on SF of directing Hetch Hetchy generation to SF in the new draft report. It in no way concludes that Hetch Hetchy generation should not benefit SF residential users. However, we do state the facts regarding the current and future use beneficial use of Hetch Hetchy generation, given contractual and physical limits and the role of Hetch Hetchy as the water supply for the City of SF. We also clearly point out that if, the future, Hetch Hetchy can be used to supply retail*

electric ratepayers with cost-effective power supplies it should do so. In regards to the current use of Hetch Hetchy power in SF, we have put this fact into the revised report.

b. The business arrangements between Hetch Hetchy and PG&E are not addressed. If the City municipalizes, the PG&E contract is null and void; no analysis on that has been addressed here.

Response: In Chapter 6 of the revised report, we address this issue under the changing environment of restructuring. For example, the transmission services proved by PG&E to transport Hetch Hetchy power are to be transferred to the Independent System Operator (ISO). See also section 4.B.3 of the revised report.

c. The study states that the only basis on which the Districts would consider renegotiating the contract would be if they want to get out of paying for power priced above market. What legal consultations formed basis for this conclusion? (Need to define source.)

Response: This statement was not based on any legal analysis but on certain economic assumptions that are speculative in nature. Therefore, this statement has been eliminated from the revised report. We do know that Hetch Hetchy Water and Power does believe that its current contractual arrangements with the Districts is, in opinion of HHW&P, very beneficial to the citizens of SF and have detailed the rationale for this conclusion in the revised report.

d. Class 1 power is a legal issue -- would be good to have a definitive legal opinion in the study.

Response: The City Attorney for SF has, in the past, issued detailed legal analysis of this issue. We could provide a copy of that document if the TRC believes it necessary.

e. With respect to Class 3 power, the issue seems to be that this is being sold at wholesale prices and what we are talking about with respect to making Hetch Hetchy energy available to City residents is an accounting issue in that it doesn't matter whether we buy bulk energy and sell it to the residents, or if we supply it from Hetch Hetchy -- the determining factor is the impact on net revenues to the City. If this is the point the study was trying to express, it was not presented clearly.

Response: We believe the revised discussion of this issue in the revised report clarifies the matter, especially section 3.A.3.

f. The availability of Hetch Hetchy energy after 2015 should be addressed and its value quantified.

Response: *We have addressed this issue in the revised report report in two ways. First, we state that the contract for with the districts expires in 2015. Second, we state that if there are greater benefits to using this power in SF after 2015, as opposed to continued sale to other parties, Hetch Hetchy can do so under the provisions of AB 1890; the electric industry restructuring legislation.*

5. Comparable Cities Analysis.

   a. What rationale was used to select the six cities?

Response: *This was discussed at pages 10-11 of the Draft, and is discussed in the revised report at pages 1-2, -3, -13 and -14.*

   b. Were these public power cities given a chance to review the sections of the report that relate to them? Why weren't cities outside of California addressed, since municipalization experience inside California is limited? What is the basis of the assumption that the average cost differentials between existing public power and IOU electric utility systems are "dominated" by the municipals' lower gross cost of capital?

Response: *See the answer to item 2h above on muni review. Cities outside of California were addressed to the extent required by the scope of work and to the extent required to determine whether there is any relevant experience in recent years, especially of large cities municipalizing. As the revised report notes, there is no such experience, with the largest municipalization in the last 15 years including only about 1/20th the number of customers that SF does. (The question seems to assume there is some relevant experience, and wrongly implies that we did not consider whether there was any.) The third question here mis-states our usage.. We did not assume the stated dominance, but instead proved it by doing the analysis in the table at page 13 of the Draft and in the associated text. This example of the allegation of "unsupported assumptions" illustrates a general point about that allegation here: it errs on this report (usually relying on labeling something an assumption when it is not and overlooking the direct demonstration of the conclusion).*

   c. On p.20 regarding the Trinity County PUD, the study indicates that rates are 20% less than PG&E's rates according to a June 1993 bond prospectus. It isn't clear whether the 20% rate difference cited is due to municipalizing or to reductions in PG&E rates.

Response: *The difficulty in using these figures is recognized in section 1.C.1 of the revised report as springing from the confusion in the source document cited. It appears that the rates are lower due to municipalization. The comment seems to miss the fact that the PUD now serves the area and sets its rates.*

6. AB1890. The bill is referred to, but the impact of this bill on the municipalization decision is not addressed.

   Examples:

   a. What are the projected rates for each class of user (i.e. residential, small commercial, industrial) in SF in light of this bill? The study should indicate trends that would give industrial consumers benefits early (e.g. through phase-in of direct access), timing of expected benefits for residential and small commercial consumers, etc.

Response: Rate design issues are not the subject of this report. However, the impacts of AB 1890 on the average cost of electricity are addressed in chapter 4 of the revised report.

   b. What is the impact of AB1890 on renewables and DSM/energy efficiency projects?

Response: We have briefly mentioned the provisions of AB 1890 on continued renewable and DSM programs in chapter 6 of the revised report. However, these provisions in AB 1890 do not materially impact the focus of this report, i.e, the economics of municipalization. We do comment on the fact the decisions in the area of DSM will be localized (as opposed to PG&E/CPUC control) if a municipal electric utility is established in SF.

7. Electric Restructure. A number of issues were raised that don't attach any value. Example: Stranded costs; what is SF's share?

Response: Since SF is about 1/15th of PG&E's electric system, it would account for about that fraction of stranded costs. On the other hand, SF's share varies with the measurement used -- as between revenues, energy usage, peak load, etc. Moreover, because these costs will be paid via the CTC, they are not affected by the municipalization decision. Hence, the issue is irrelevant, and ahead of the thrust of some other comments, we did not include irrelevant material.

8. Environmental Issues.

Response: Before restating the TRC questions, we conclude after a review of the comments that much if not all this presentation missed the mark as to the central issue, i.e., what material changes will occur under muncipalization as opposed to continued PG&E service. Therefore, much of this discussion in the original draft has be exorcized from the revised report.

   a. There are inconsistencies in the discussions about energy efficiency programs. On p.27, the study mentions that some municipals use their utilities as revenues for their General Funds. This gives cities an incentive to sell more electricity and a disincentive to save electricity through energy efficiency. This important point needs to be addressed in context of municipalization.

Response: *No inconsistency was cited, so we cannot respond to that part. However, if munis use their electric systems as a source of revenue for other purposes, then the incentive to sell, etc. follows. We expressly assumed that SF would not use a muni electric service in this manner, but of course we cannot guarantee that. On the other hand, the matter would be subject to local political control with a muni. There is a potential issue here, we agree, but how one views it depends on how one views the effectiveness of the muni and IOU-regulatory governing processes, as well as what the goal is (as between conservation, low rates, low taxes, etc.).*

b. Some places, indicates municipals may want to offer DSM services, but discussions in the study are inconsistent. In other places, e.g. in "optimistic" case, show the trend in DSM as declining. This should be assessed in context of consistency with AB1890.

Response: *See the immediately preceding two responses. We believe our analysis is fully consistent with AB 1890 provisions. In any event, we recognize these concerns as serious and perhaps significant ones for municipalization; the problem is that the outcomes are speculative as being subject to local political decisions after municipalization.*

c. Renewables paragraph on p.135 seems to argue that there is no benefit to investing in renewable energy, and the price assumptions relied on seem incorrect.

Response: *See the general comment under 8 above. We definitely do not mean to imply there is no renewables benefit; that determination must be made specifically for each situation, and much renewables development has already passed the test, not just in analysis, but also in use.*

d. Appendix I-A, Table 1-5, page 2 of 2, LADWP indicates they are doing DSM. In fact, LADWP has cut all DSM programs other marketing and low income services, which raises questions about accuracy of the rest of the table.

Response: *Survey methods are subject to respondent error, especially for responses from large organizations. This table has been cut from the report.*

e. On p.92, study indicates an assumption on the price for DSM as equal to direct access bulk power (3.55 cents per kWhr) vs. California experience is 2 cents per kWhr.

Response: *See the item 8 general response above.*

f. On p.132, last paragraph before Section C. uses DSM as equivalent to load management, which is very different in character from energy efficiency and needs to be corrected/ clarified.

Response: *See the item 8 general response above.*

g. Fail to mention that DSM has been found to be much more economic than building new plant.

Response: See the item 8 general response above and the response to item 8c.

9. In-City Generation.

Response: Before restating the TRC questions, we concluded, after a review of the comments that the role of "In-City generation" is best explained within the context of AB 1890 and the risk associated with the creation of a separate service area in SF through muncipalization. We have made changes in the revised report to reflect this. In addition, we cite the source of distribution capacity expansion forecasts.

a. On p.49 re: potential outages and the need for local generation, didn't address the fact that during the big August 1996 outage, the Hunter's Point plants did stay on and serve the City.

Response: See the previous response to item 9.

b. On p.50, don't address the AES proposal to build a new power plant.

Response: As to the AES proposal to build a new plant in SF, we comment on this issues in the revised report, however we do not speculate on the success or failure of AES proposal because we have no basis for doing so.

c. On p.52, state that PG&E forecasts capacity increases will be required in the network by the year 2004, and there is no citation for that. Then talk about the radial load area, but don't talk about whether PG&E forecasts any need for capacity increases there.

Response: See the general item 9 response above.

d. The discussion of Hunter's Point on p.66 is useful, but need to look at AB1890 in context of PG&E being paid more money when they run these dirty plants.

Response: See the general item 9 response above.

10. Miscellaneous

a. On p.54, wonder if PG&E has some modern digitized mapping (aka "GIS")?

Response: PG&E does have this, but it will not share it with us at this time.

b. "Peak Load and Customer Growth" on p.59 states that investments in distribution systems are driven primarily by non-coincident peak of its customers. Modern cost allocation recognizes the important role of energy use in terms of sizing the electric distribution system.

Response: *We stated that area non-coincident peak demand "primarily" drives the sizing of the distribution system. This is a fact. While energy use may play some role in specific components of the distribution system, the over-arching (primary) engineering requirement is that the distribution system must meet the maximum peak demand of the customers it serves. If this question addresses a rate-design issue, we again state that rate design is not the subject of this study.*

c. Need to define coincidental vs. non-coincidental peak, and how it is used differently for generation capacity vs. distribution.

Response: *We have done so.*

d. On p.78 and other places, assumption is made that tax-free bonds could not be issued for purchase of distribution assets. Is this valid?

Response: *See response to item 1q above.*

e. A major concept has not been addressed: the importance of good management to any successful business enterprise -- whether public or private.

Response: *This point goes without saying, and we did not say it. While we wholeheartedly agree with the point of the question, we have no way to forecast good or bad management results, Thus, after many second thoughts, we decided that any discussion of this matter would be viewed as either speculative or prejudicial or both, and the new draft report reflects this opinion.*

GENERAL COMMENTS

1. Process. Concerns were expressed by one member of the TRC regarding the contractor selection process.

a. PUC overturned recommendation of the Technical Review Committee in selecting ETAG as the contractor to perform this study.

Response: *No response is required from ETAG on this item.*

b. On May 6th, ETAG represented to this committee that they were paid only $1,000 in work for PG&E. Ron Knecht made the same representation before the SFPUC.

On June 4th, ETAG wrote that they received more than $140,000 in fees from PG&E.

Response: This comment mis-states the record. The record is very clear that the $1,000 figure refers to the last three years for ETAG, while the $140,000 figure includes the work over ten years done for PG&E by the team members' firms and in which they were involved; although they were involved in this work, $140,000 includes others who were involved but who are not part of this project. Also, this comment is biased, because it fails to reflect that on the same basis over seven times as much work was done for the muni and related side.

c. The RFQ required each contractor submit one feasibility study. ETAG hasn't done this; haven't done it to date. A key portion of the RFQ was not met by this contractor.

Response: ETAG submitted the Memphis study, in which its team leader and another member were key participants and co-authors. Memphis has a distribution muni and was considering municipalizing its energy supply, instead of continuing to purchase from a single supplier. SF has a municipal energy-supply operation and is considering municipalizing its distribution system. Thus, these two projects are comparable. In addition, another team member has done municipal feasibility studies for Chicago, which were made available to CCSF within the confidentiality restraints set by Chicago, as his client. By themselves, either of these items would satisfy the requirement (if the specification of these documents is truly a requirement, and not merely a desirable indicator of experience.) In any event, ETAG also submitted other relevant experience covering all elements of this study, with the vast majority of that work for munis.

One member of the TRC has recommended investigation of the process which resulted in selection of ETAG as contractor for this study.

Response: No response is required from ETAG on this item.

2. Two members of the TRC recommend that the SFPUC terminate the ETAG contract and not allow this study to be issued in final form.

Response: No basis is given for this recommendation, and there is no reasonable basis, because we have complied with the scope of work (exceeded it, actually) and produced an unbiased reliable study. None of the comments have shown any substantive error that affects the results, nor even hinted at such.

3. The consensus opinion was that ETAG should be present at all future meetings of the Technical Review Committee.

Response: We are willing to do so, as reflected by the fact that we offered to be present at that meeting and came upon being called after it began.

4. Several members of the TRC suggest that a copy of the draft study be provided to the six "comparable" cities plus the APPA, and that they be requested to provide formal written comments.

Response: *No response is required from ETAG on this item. It is in the hands of the SFPUC.*

5. One member of the TRC suggests that the City Attorney prepare an opinion as to the likely impact on the Raker Act if Hetch Hetchy renegotiates the Districts' contracts.

Response: *No response is required from ETAG on this item.*

Carl Blumstein, a member of the Technical Review Committee (TRC) assembled by the City and County of San Francisco (CCSF) for this project, prepared a memorandum (on the next page) with two comments on ETAG's Draft Preliminary Feasibility Study. This page responds to those two comments.

Response: (1) Market Power. The concern stated here about the market power of the owners of San Francisco power plants, due to the plants' unusual local value to the SF distribution system, was relevant before passage in September of Assembly Bill (AB) 1890. AB 1890 fully controls such market power, and thus obviates the need for the muni threat in this regard. In fact, on the local reliability and ancillary services issues, AB 1890 portends a threat to municipalization if its implementation leads to reliability-rates de-averaging as a response to muni initiatives. CCSF might have an advantage in bidding on these power plants because it is exempt from state and federal income taxes, as most bidders would not be.

(2) Legal Advice on Valuation. Contrary to the claim in this comment, our assignment of methods and values to the various cases for analysis was based at least as much on legal precedent as on economics. Also contrary to the comment, our position on OCLD is that it may not be admissible, per se, as a basis for valuation in California (not mainly, as suggested, that it is unfair to PG&E). The economic error OCLD incorporates is explained to help the reader understand why it is not used in condemnation valuation or voluntary transactions. The suggestion that the CPUC would shift revenue responsibility from SF to other areas overlooks the point we made in section 2.A of the Draft (and even more so in the revised report) that this issue has been decided to the contrary by the CPUC and actively relied on by it in many municipalization, street-light and subdivisions filings continuously. Assuming a change in this long-established, widely applied precedent would truly be to "assume you have a can-opener", per the punch line of an old joke about economists. We think The City is best served by our sober advice on this matter, not by making a wild leap of faith and calling it "a more neutral position".

Dian Grueneich and Wally McQuat, consultants to Hetch Hetchy Water and Power (CCSF/PUC), have each also prepared comments, beginning at the second following page. Each item in their comments has prompted a change or a discussion with them of why no change was made (we believe to their general satisfaction) -- mostly the former by a large margin. Hence, we present those comments with only the response that their implications have generally been adopted.

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October 21, 1996

MEMORANDUM
TO: Laurie Park
FROM: Carl Blumstein CJB
SUBJECT: Comments on ETAG's Municipalization Report

I am sorry that I was unable to attend the Technical Review Committee meeting on October 16. I have two suggestions for additions to your October 17 memo to ETAG.

(1) Market power. The ETAG report focuses on the potential opportunity to exploit The City's lower cost of capital as the primary reason to consider municipalization. However, the ability to protect San Franciscans from market power in the restructured electricity industry may be an equally, or even more important reason for keeping the municipalization option open. Given the existing transmission network, providing electricity to San Francisco requires the operation of certain in-area power plants. The owner of these "must-run" power plants, be it PG&E or some successor company, is going to have considerable market power that it could exercise to raise the price of electricity from these plants to high levels. Whether this kind of market power will adversely affect San Franciscans depends on factors that are not yet known such as transmission pricing rules and what regulations will be applied to must-run plants. Just the *threat* of municipalization can serve to discipline market power. That is, even though the plant owner has market power, the market power may not be used if the owner fears that using market power would cause the plant to be taken. Given the uncertainties in the current situation, The City should keep its options open. I don't think that the next step is a detailed valuation study. Rather, I think The City should explore some alternative strategies such as buying the power plants without buying the distribution system or becoming a power marketer/aggregator.

(2) Legal advice on valuation. ETAG places too much emphasis on economics in its discussion of the valuation of PG&E's San Francisco distribution assets. Economics typically addresses efficiency, not equity. Economics doesn't have much to say about what is fair. That is a matter for philosophers and jurists. In its report ETAG argues rather strongly against the original-cost-less-depreciation (OCLD) method of valuation--a method that would be favorable to The City. ETAG's position is that OCLD valuation would be unfair to PG&E because the City's taking of PG&E's distribution assets in San Francisco would deprive PG&E of a revenue stream that has a net present value that is greater than the OCLD value. The reason for this is that the revenue stream from San Franciscans includes both funds sufficient to amortize the OCLD and a subsidy to PG&E customers with higher distribution costs. However, one could also argue that if PG&E received the OCLD for its San Francisco assets it would not lose the entire revenue stream because the California Public Utilities Commission would shift the cost of the subsidy back to the higher-distribution-cost customers. The City would be better served if ETAG took a more neutral position in its report.

The Staff of Hetch Hetchy Water and Power (HHWP) prepared a memorandum with comments on ETAG's Draft of its Preliminary Feasibility Study. Working from a computer file of that memorandum, ETAG has provided answers to those comments. This document includes each comment as taken from the Staff memorandum, followed in a single paragraph by ETAG's response to the item (beginning "***Response:***" and in *italics*).

PUBLIC UTILITIES COMMISSION
CITY AND COUNTY OF SAN FRANCISCO
HETCH HETCHY WATER AND POWER

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MEMORANDUM

TO: ETAG

FROM: Hetch Hetchy Water & Power (HHWP) Staff

SUBJECT: Comments on ETAG's Preliminary Draft Municipalization Study dated October 11, 1996

DATE: October 25, 1996

Staff has extensive comments on ETAG's preliminary first draft. Comments on the overall presentation are addressed under "General Comments". Technical comments are organized by issue area.

Staff stated at a meeting of the Technical Review Committee (TRC) held October 16, 1996 that we could neither support nor reject the conclusions and recommendations presented in the current draft study for the simple reason that we cannot track the assumptions underlying these conclusions and recommendations. This is due in large part to several principal defects in the report as currently structured:

- It is difficult to track the study assumptions with respect to valuation methodologies employed, the range of values applied to critical variables, and the basis for estimating these ranges of values.

Response: *This comment apparently refers mainly to the capitalized income method, for the other methods were documented. In any event, detailed, clear documentation, fully traceable, is included in chapter 2 of the revised report.*

- The report often digresses into speculation and assertions that 1) cannot be readily substantiated and 2) are irrelevant to the scope and/or conclusions of the study. As a consequence, the reader is left befuddled by extraneous comments and academic arguments.

Response: *This criticism, like many here, deals in labeling and characterizing the Draft, and does not provide enough specificity or detail to be helpful. More helpful would have been an additional sentence referring to specific examples of these problems below in the body of these comments (e.g., "See items X.1 and Y.2."), if any there are. Nonetheless, we have thoroughly edited the Draft with these comments in mind and tried to do so in a way that is fully responsive to this comment to correct any shortcomings in this regard.*

- The report is internally inconsistent, with broad assumptions and statements made in some places that are refuted in others.

Response: *See the previous comment and answer. Item 5a under "General Comments" below appears to be a specific example. See our response to it.*

Staff have identified general and technical comments to this preliminary first draft which are provided below. We are deferring comment as to the validity of the valuation and other assumptions employed until issuance of the next draft, at which time we will expect to be able to track and understand the various assumptions which support the study findings and recommendations.

Response: *There is a fundamental misunderstanding here to the extent that this comment suggests that valuation is an assumption we made. By its nature, valuation is not an item one reaches by assumption in this work -- and we certainly did not do so, but instead based our valuations estimates on rigorous analyses and meticulous calculations. The revised report attempts to better document that work and to meet this criticism and the others here.*

GENERAL COMMENTS

1. Structure and Presentation Format. The TRC provided extensive suggestions for modifications that would facilitate understanding of the report. Staff supports all of these recommendations.

Response: *See our response to TRC comments items 1a-q.*

2. Relevance of Discussions and Arguments. The TRC suggested that the narrative of the report be confined to that which is directly relevant to the study conclusions. Staff strongly supports this recommendation.

Response: See, first, our response to all TRC comments to which this comment makes reference. Second, we have attempted in our rewriting to reflect and satisfy this concern.

3. Biased Comments. The report contains off-hand comments which, either due to lack of balance or poor editing, tend to convey personal viewpoints rather than substantiated facts, and do not belong in an objective study of this type.

Examples:

a. On p.27, the report discusses PG&E's proposal for area cost averaging. The authors speak very positively of PG&E's proposal ("industry leader", CPUC "supportive of the work") but fail to address the strong opposition to the proposal from many customer groups.

Response: Both of the quoted comments are true: PG&E is an industry leader in this area for doing creative work in it that other major utilities have not; and the CPUC has been supportive (as shown in its decisions on this matter), while, as we noted, it has not adopted it yet for ratemaking. Neither of these facts is diminished by the fact that some customer groups, for various reasons, have opposed adoption of this work for ratemaking. But the comment is biased for failing to note that some customer groups have also strongly supported it.

b. On p.34, footnote #5 is dedicated to discrediting testimony of a competitor. The comment appears gratuitous and not professional. If the argument is central to the discussion, it ought to be presented from a positive viewpoint as a comment on the methodology utilized by ETAG.

Response: The argument is central to the discussion, and it cannot be stated from a positive viewpoint, because the simple fact is that the cited paper is wrong just as stated. There is nothing the least bit gratuitous or unprofessional about pointing this out when it is fully relevant to the matter at hand and when the cited item is not obscure, but is being promoted by partisans in this matter -- as is the case here on both counts. In any event, because the substantive point has been made in our main text, we have removed the footnote reference.

c. On p.109, the statement:

> "The Pessimistic case in the Municipalization scenario increases the per customer costs discussed in the above paragraph by 15% to account for ***possible inefficiencies such as those which have***

> ***plagued the Municipal Railway system and other municipal services for many years in SF and elsewhere.*** [emphasis added]

is inflammatory and unsubstantiated.

Response: *This comment is wrong on both counts. The Muni Railway problems have been widely discussed by CCSF officials, the press and public -- including lately in public and on radio by at least one Supervisor in discussing the subject of this report. Citing a local example of problems that can arise to illustrate the problems is an economical (i.e., short) and effective exposition, not inflammatory. On the other hand, spending time and space trying to "substantiate" what is already well-known would draw accusations of "government bashing" from partisan quarters. This comment apparently missed the key presence of the word "pessimistic" in the cited text. Because we have changed the case structure in the revised report, the cited text has been deleted from it.*

4. Documentation of assumptions and impacts on study results. The report fails to explain the basis for key assumptions employed and the resulting impact of these assumptions on the study results. The TRC has requested a table of assumptions in which all of the assumptions employed in this study are documented and the resultant range of impacts indicated for each. Staff strongly supports this recommendation.

Response: *See the response to TRC item 1e and 5b, items that address this matter. See also the response here above to the second bullet at the beginning.*

5. The report digresses into a multitude of issues and fails to link them together where appropriate, or to distinguish between them when different. For example:

   a. The report touches upon the concept of the relationship of distribution costs to population density, but fails to pull the point together. On p.33, the report states: "... a municipality in a low-cost area -- which our reports show SF is --". The basis for declaring SF a "low-cost area" is never substantiated. The statement appears again on p.43. Further, it directly conflicts with statements elsewhere in the report (e.g. p.84, "... the City [is] most costly to serve.") which relate to discussions about PG&E's San Francisco Operating Criteria (SFOC) and transmission constraints into the northern Peninsula. (See 6.b. below.) Whichever case believed to be true requires substantiation.

Response: *On their face, the cited items refute the "directly conflicts" criticism. The matter discussed at page 43 expressly refers to the "distribution system", while that at page 83 the sentence refers expressly to "transmission". Also, the page 43 claim is substantiated by the difference between PG&E's SF and system-wide distribution investment and operating costs. In the revised report, responding to this item, we tried to better link and distinguish matters.*

b. The report spends considerable time in Chapter II discussing PG&E's San Francisco Operating Criteria (SFOC) and the costs of acquiring PG&E's San Francisco plants. However, it is unclear whether the subsequent chapters assume acquisition of the generating plants, whether the authors themselves are recommending the plants be acquired, the basis for any such recommendation, and the impact on the cost/benefit of municipalization.

Response: Pages 63-64 and 77 show and state explicitly that we did not assume acquisition of the plants, but instead considered this matter a "risk factor". Further, all tables in chapter 4 show distribution, transmission and substation costs, but no generation -- so this matter should be clear. However, in the revised report, we sought to be even more clear on this and all other matters, in keeping with this criticism.

6. The report fails to consider its audience. The report assumes the reader is an expert in the electric business and the current electric industry restructure which is in progress. However, inasmuch as:

   a. The report should be written so that any informed reader with a grasp of basic economic theory and business practices can understand the report; and

   b. Electric business and industry restructure concepts are used incorrectly and inconsistently throughout the report;

   it is difficult for even experienced electric industry professionals to understand the report. Staff supports the TRC comments for extensive changes to the report structure and presentation to facilitate comprehension. Further, staff has provided below extensive comments with respect to errors or lack of clarity in technical content which must be corrected.

Response: See our responses to TRC comments 1a-q, as well as to the specific items below that are cited in this comment. On item 6b here, see our response above to the second bullet item in Staff's introductory remarks.

TECHNICAL COMMENTS

There are errors, inconsistencies and unsubstantiated comments throughout the preliminary draft report. The major ones are addressed below; there are others. Many have already been addressed by other members of the TRC and other parties.

At this time, staff are not offering comments to the appendices, most of which are either irrelevant to the study objectives or only useful as work papers. The appendices should

be cleaned up and only that which is directly relevant to the study objectives and recommendations included in the next draft of the report. All of the comments provided above should be considered when cleaning up the appendices. The exception is that Appendix III-A, in which Hetch Hetchy operations and contractual commitments are specifically discussed, will be addressed herein.

Response: On the first paragraph, see our response to the second bullet item above in Staff's introductory remarks. On the second paragraph, we will of course, consider and use to the fullest extent possible all of Staff's guidance in the appendices (workpapers), as well as text.

1. The Municipalization Decision. At the heart of the municipalization issue is an understanding of the various types of costs underlying the price of retail electric power, which of those costs are likely to change with municipalization, and the expected magnitude and range of such costs. This fundamental concept is absent from the current draft report. In order to facilitate understanding of the municipalization decision, staff recommends the following presentation approach:

Response: It is not at all absent, but is in fact shown in detail in the tables in chapter 4.

   a. An illustration of the build-up of costs which together comprise the delivered cost of a unit of electricity sold to PG&E retail customers on a cents per kilowatt hour basis. This breakdown should be provided on a comparative basis for current (1996) and projected (2002, after the primary CTC recovery period), both before and after adjusting for the expected impact of municipalization.

Response: A 1996 breakdown is not useful, because municipal service could not begin before 2002. However, Tables 4-1, -2 and -3 (ES-1) incorporate these proposals for the years 2002 and 2011.

   b. Each element of cost [energy, transmission, distribution, customer charges (metering, customer billing and accounting, customer service, etc.), cost of capital, rate of return, other?] should be described in lay terms, along with a brief discussion as to whether, why and to what extent this cost would be expected to change with municipalization.

Response: The discussions in the revised report related to the chapter 4 tables attempt to satisfy directly this comment.

   c. Those components which are expected to change should include an expected value range in cents per kilowatt hour, and the assumptions underlying the bounding of the estimated range.

Response: See the previous comment. Note, though, that the case structure has been greatly simplified in the revised report.

d. The result would be a range of retail electric prices in cents per kilowatt hour for each of the four categories (1996 vs. 2002, with and without municipalization) presented.

Response: See response to item 1b here.

Example:

	19 96		20 02	
	PG&E System Average	With Municipalization	Projected PG&E System Average	With Municipalization
Energy	xxx	xxx	xxx	xxx
Transmission	xxx	xxx	xxx	xxx
Distribution:[1]				
O+M	xxx	xxx	xxx	xxx
Ownership	xxx	xxx - xxx	xxx	xxx - xxx
Customer Costs	xxx	xxx	xxx	xxx
Cost of Capital	xxx	xxx	xxx	xxx
CTC	xxx	xxx	xxx	xxx
Rate of Return	xxx	xxx	xxx	xxx
Others[2]:				
Variable A		xxx - xxx	xxx	xxx - xxx
Variable B		xxx - xxx	xxx	xxx - xxx
Variable C		xxx - xxx	xxx	xxx - xxx
Total (range):	xxx	xxx - xxx	xxx	xxx - xxx

Those costs that are expected to change with municipalization should be clearly indicated. For example, it is unlikely that energy costs would change significantly with or without municipalization (see discussion under item 7, "Energy Supply Issues", below). Transmission costs should be the same, irrespective of who owns the distribution system. However:

[1] Distribution costs clearly change with the municipalization decision. It is not clear that O+M costs should be expected to change, but certainly acquisition of the distribution system will result in some difference in ownership costs.

[2] The report indicates that tax exempt bonds may or may not be available to

purchase the distribution system. Use of a sensitivity variable (such as Variables A, B or C above) could illustrate the impact on the result with and without tax-exempt financing.

[Note: The 1996 and 2002 dates above are selected for illustrative purposes only. These dates seem significant in context of the planned schedule for a transition to a competitive electric marketplace and 2002 is the year selected by ETAG as "... the earliest realistic date for Municipalization ..." ; nevertheless, if the study concludes that the year 2010 would be the ideal point at which to municipalize, that should be the period presented. The report should state very clearly which date was chosen for the municipalization assumption and why that date was chosen.]

Response: We attempted to make the revised report fully responsive in this area, as well as others. As stated, 2002 is simply the earliest feasible date; since the economics does not change in real terms over time, we used that as the start date (as convenient as nearest in time to the present among possible start dates).

2. Survey of Other Municipals. Under the Scope of Work, the principal objective of Chapter 1 is to present the results of a survey of public vs. private power rates, why and how these rates are different, common characteristics of successful municipally owned and operated utilities, and potential obstacles to overcome. There is no question that on an average basis, rates charged by public power entities are lower than those charged by private entities. The principal factors intuitively are cost of capital and rate of return which are known to be different for public vs. private entities. These simple concepts are not conveyed effectively in Chapter 1 because too many facts and figures are presented, when the discussions should instead have focused on issues directly relevant to the municipalization decision. For example:

   a. Rate design and rate policy are not relevant to the municipalization decision; hence, the attention focused on comparing rates by user class (i.e. residential, commercial and industrial) is not relevant.

Response: This conclusion is arguable, but because it is and because the scope of work does not address this subject, we have withdrawn it from the revised report.

   b. Adjusting public power rates for the purpose of comparison with rates of neighboring IOUs may be useful, but the objective and conclusion of that adjustment is not well expressed.

Response: We have restructured and rewritten this section to make it clearer.

c. The discussion on stranded costs (p.23) is inappropriate. More specific comments on the treatment of stranded costs in the report are provided under #5 below.

Response: This comment would be helpful if it stated why it believes the discussion is inappropriate, instead of just labeling it. We disagree with the label. We have added to the discussion to improve it. We respond to the section 5 comments here below.

3. Values and Valuation Methodology(s) Employed. The text of the report spends far too much time expounding upon academic aspects of the various types of valuation methodologies. Again, it is important to consider the audience and to explain the difference between the various methodologies in simple lay terms, then to address briefly which method(s) are most applicable to the municipalization issue and why. Where the valuation methodology is not generally applicable to the issue at hand, this should be stated along with a brief statement of the reason(s); and then not given much additional time and attention. The entire write-up on valuation methodologies in pp.30-43 should be condensed into a maximum of 3-5 pages, focusing the discussion on which valuation methodologies would be most applicable to a condemnation valuation and why, and referring to exhibits in the Appendix if necessary to facilitate understanding.

Response: We respectfully disagree to a certain extent. As stated in the revised report, there is a certain level of complexity and necessary technical understanding that is inherent in the issue, serious policy analysis requires that decision-makers be presented these matters. In accommodation to this comment, we rewrote this section and offered a reader roadmap that allows readers to short-circuit it if they choose, but we believe that which remains is essential.

We have the following comments on specific points or passages relating to valuation.

a. On p.29, the report states: "(PG&E has already stated its SF system is not for sale.)" No authoritative cite has been provided for this statement.

Response: We have provided a citation in the revised report.

b. The scenario titles: "Base Case", "Pessimistic" and "Optimistic" imply a qualitative judgment and tend to evoke an emotional response. "Mid", "High" and "Low" would suffice.

Response: Some people may infer a qualitative judgment and make an emotional response, but the titles do not imply any such thing, and their use was explained. Nonetheless, in restructuring the case structure, we have, at Staff's request altered this terminology to "base", "high-cost" and "low-cost".

c. The study objective was to identify a range of valuation results given accepted methodology approaches. Once bounded and identified (i.e. "Mid", "High", "Low"), refinements of these basic valuation approaches do not enhance the decision making process at this preliminary stage. Therefore, for example, the "base-case income-method variant" (p.30 and elsewhere in the report) is not particularly useful, and only serves to confuse the reader.

Response: *Although we find a five-case structure useful (showing two outer limits, two reasonably expected limits and a representative value), in response to this comment, we have restructured the presentation based only on the three interior cases. The "base case variant" method is now the low-cost case, and we believe it is highly useful for being based on the income method, as we explain in the text. Failure to keep this case, we believe, would bias our estimates quite high.*

d. As several other respondents noted, the income valuation approach is given substantial attention in the report text but not tied to the study conclusions.

Response: *This is wrong, for as noted above, it produces the base case variant, which is relied on almost as much as the base case (thus, it's tied). In response to this comment, we have extensively rewritten this material to clarify matters. See also our response to TRC item 3c.*

e. The discussion of GAAP ("generally accepted accounting principles") on p.32 is not essential to an understanding of the concept of original cost and is presented incorrectly. The statement:

> "... even within the constraints of generally accepted accounting principles (GAAP), ***an owner has enough leeway to set the accounting values for assets to levels significantly different from current economic value*** in their current and expected use and business context." [emphasis added]

is incorrect. There are specific rules governing the recorded value of assets, and not all that much "leeway" if the rules are properly applied. Further, footnote 4 on p.32 refers to book value as "either net book or market value" without providing a proper context (i.e. the accounting principles of "conservatism", "lower of cost or market", "temporary" vs. "permanent" increases in asset values, etc.). This discussion distracts the reader for no useful purpose and confuses the issue by addressing the concept incorrectly and incompletely.

Response: *To the contrary on the last sentence of this comment, on the face of the Draft, a*

useful purpose is clear: to show important evidence that book values are not reliable for valuation purposes and reasons they are not used and cannot be used. In response to this comment, we have rewritten this section to clarify the relationship between GAAP, book value and economic value.

f. The write-up on the income valuation methodology (pp.33-36) departs from the description of the valuation methodology to expound on stranded costs and ends with the conclusion that the income valuation is interesting to economists. The presentation is fragmented, confusing, and does not seem to serve any purpose since there is no indication that this method is used in condemnation settlements.

Response: We have rewritten this section for clarity and to explain the key role of the income method and of stranded costs in electric-system valuation generally and in the context of this analysis (CTCs) in particular.

g. On pp.44-48 and pp.52-53, the long description of distribution assets is not necessary. A general discussion as to what a distribution system is (as differentiated from transmission), coupled with a brief description of the SF distribution system, would be more appropriate. More detail could be included in an appendix if needed.

Response: We have rewritten these and other sections in response to this comment to simplify the presentation and eliminate a great deal of background material that is not essential.

4. Ongoing Ownership and Operations and Maintenance (O+M) Costs. The principal issues with respect to ongoing costs are:

- Whether, why and to what extent ownership and O+M costs for the SF distribution system may be different for CCSF vs. PG&E ownership of the system, and
- The impact any such differences may have on the municipalization decision.

Chapter 3 is replete with incorrect and/or irrelevant statements. Further, key restructure concepts are incorrectly described and misapplied.

For example, throughout Chapter 3 and elsewhere in the report, reference is made to "direct access power being available under Municipalization". There is no special category for direct access power provided by a local municipality. "Direct access" is a

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concept independent of the municipalization decision.[1] Yet, Chapter 3 treats direct access as the predominant factor underlying operations, maintenance and repair costs.

The presentation of the build-up of costs per kilowatt hour suggested under item #1 above, "The Municipalization Decision", would be far more effective in addressing and presenting the continuing ownership and O+M costs relevant to the municipalization decision.

a. Throughout Chapter 3, "direct access" was used (incorrectly) interchangeably with other restructure concepts, including "load aggregation" and "bilateral contracts". When used in the incorrect context of "load aggregation", the report treated "direct access" as a potential benefit that CCSF could have over the "Business As Usual" (BAU) assumption; i.e. with PG&E as owner and operator of the SF distribution system. The benefit assumption rests not only on a fundamental misunderstanding of what is "direct access", but on unsubstantiated "opt-in/opt-out" arguments used elsewhere in the report; i.e., that a municipalized entity somehow has an advantage over a non-municipal distribution system owner because "The Muni consolidates small users by default rather than needing to persuade them to sign up, as an independent marketer under BAU would have to do." (p.94) This position is flawed in several respects:

   1) The concepts of "direct access" and "load aggregation" have been confused and used incorrectly.

   2) The "opt-in/opt-out" argument has questionable validity and is not substantiated in any meaningful way anywhere in the report. Even if it could be proved that the sheer process of having to designate an alternative supplier would be a deterrent for most end users and thus the owner of the distribution system has a preferential position as the supplier of choice, that advantage would be the same for any owner of the distribution system,

---

[1] By CPUC decision and state law, PG&E must allow non-PG&E entities to offer direct access to retail customers beginning in 1998 on a phased-in basis, with all customers having the right to choose their own electric supplier by the year 2002. If CCSF does not municipalize, all of its residents and businesses will be able to choose direct access or PG&E as their electric supplier by 2002. If, however, CCSF municipalizes, it will have no legal obligation to provide direct access (although it is likely that CCSF residents and businesses will pressure CCSF to provide customer choice). It can simply serve CCSF customers, even in 2002, as municipal utilities currently provide service. The caveat is that if CCSF seeks to serve retail customers outside CCSF boundaries, the concept of "direct access service by CCSF" arises. CCSF could still provide municipal, bundled service to CCSF residents, but non-CCSF entities could compete to sell energy supplies (i.e. "direct access") to customers within CCSF boundaries (i.e. "reciprocity").

whether CCSF or PG&E, and has nothing to do with direct access.

3) Aggregation of energy supply for multiple end users is a business opportunity independent of ownership or operation of a distribution system. There is no significance in distinguishing between a municipal and an independent power marketer in this context, since it is not clear that one type of entity would be likely to have more or less success than any other aggregator.

b. The discussion of direct access vs. Power Exchange (PX) prices on pp.94-97 is incorrect and irrelevant to the municipalization decision. The report incorrectly implies that direct access is a source of supply:

> "Apart from direct access contracts, ***the other source of bulk power is the Power Exchange (PX)*** ..." [p.95, emphasis added]

In fact, a direct access customer (or its supply aggregator) can purchase energy from the PX. In addition, there are a multitude of other sources of energy supply other than the PX. The extensive discussions on pp.94-97 relating to "... the relative price of spot versus DA [direct access] ..." are confusing and irrelevant.

This incorrect treatment is carried forward into Appendix 3-A (page #s not found, but section entitled: "Direct Access Prices); Chapter 4, "Cost/Benefit Analysis" (p.117); and Chapter 5, "Other Factors Affecting Municipalization" (pp.131-137).

Response to 3, a & b: Without agreeing with all the particulars in these comments, we have completely revised chapter 3 with the Staff comments in mind in the new draft report. We have focused in on the question of how and why power supply costs to ratepayer would be different with or without municipalization. We have eliminated discussions of issues not relevant to answering this question. We have revised the text so that references to the new regulatory structure are stated accurately.

c. On p.97 and elsewhere in the report, a reference is made to "... 2002, the earliest realistic date for Municipalization ..." No rationale is given for this assumption.

Response: The rationale for using 2002 as the earliest date that municipalization can occur, is explained in the revisions to text in chapter 5 of the new draft report.

d. The discussion about the Competitive Transition Charge (CTC) on pp. 97-100 and accompanying tables and figures are both incorrect and irrelevant to the municipalization decision.

On p.99, the report refers to a statement by a PG&E employee regarding the

amount to be bonded for repayment of PG&E's CTC. First, oral statements should not be taken as the basis for a value assumption when that value could be independently verified or calculated. Second, the report goes on to state that:

> "... because of the lower municipal bond financing rate, the actual cost to ratepayers would be about 15 percent lower under the Municipalization scenario than under the BAU scenario."

This statement seems to be based on the erroneous presumption that the municipal entity would replace PG&E's bond interest expense applicable to the 10% and 20% rate reductions for residential and small commercial classes mandated by AB1890 with municipal bond funding.

Response: *We have received and reviewed updated CTC information from the CPUC hearing and have incorporated this new data along with citations into the new draft report. We have also revised the text so that the import of the CTC as it effects municipalization is clear.*

e. On p.104, it states that "... streetlight O&M [was reduced] by 50 percent in both the BAU and Muni scenarios to reflect the percent ownership of streetlight by SF." It would be more sensible to assume that the municipalization assumption would include acquisition of the 50% inventory of CCSF streetlights currently owned and maintained by PG&E.

Response: *In our municipalization scenario, the CCSF acquires all of PG&E's distribution including the remaining 50% of streetlights not now currently owned by the CCSF.*

f. The write-up relating to transmission and ancillary services is incorrect; and again, that incorrect treatment is carried forward into Chapter 4, "Cost/Benefit Analysis". The basic issue is whether there is any basis for assuming that transmission and ancillary services will be charged differently if a municipal owns and operates a distribution system vs. any other party. No persuasive argument is provided which would support the report's premise for differing charges for these services.

Response: *In response to this comment, we have rewritten these sections to clarify this issue, and numerical differences due to it are now reflected as a risk factor and contingency case.*

g. Several concepts fundamental to an understanding of this chapter have not been properly conveyed:

1) "Distribution" is a business segment separate and distinct from "energy supply" and "transmission".

2) Ownership and operation of each business segment above is subject to

different rules and regulatory oversight (although they together comprise the "electric business" and each contributes to the build-up of costs underlying the price of a unit of electricity delivered to an end user).

3) The focus of the electric industry restructure is to foster competition at the supply (generation) end. Transmission and distribution services will continue to be regulated and will charge for services on a cost-recovery basis for the foreseeable future.

4) "CTC" (Competitive Transition Charge) relates to costs associated with generation assets which are anticipated to be "stranded" during the transition to a competitive market for energy supply which is scheduled to occur during the four year period 1998 through 2001.

5) Continuing ownership and O+M costs are only relevant to the municipalization decision insofar as ***distribution costs*** are expected to be different for CCSF vs. PG&E.

Response: We have rewritten the draft report with this Staff comment in mind and have clarified the description of electric utility service by its segmented parts. We have also rewritten the text to clarify the definition of the CTC and state that the important issue is the difference in cost. See also our response to item 4 above.

5. Stranded Costs/Competitive Transition Charge (CTC). The most significant impact of CTC on the CCSF municipalization decision is not even mentioned in the report. This omitted fact is that prior to AB1890 (and the CPUC's December 1995 restructuring decision), a major potential benefit of municipalization was access by the new municipal utility to lower cost energy supplies than that provided by the local IOU. The lower cost of energy could then offset the acquisition cost of the distribution system. Under restructuring and AB1890, the municipal utility may have access to lower cost energy than the local IOU[2]. However, the customers of the new municipal utility will have to pay CTC to the former IOU in the same amount as if it remained an IOU customer. In PG&E's case, significant CTC will continue even after 2002. This change in law is ignored in the report.

Not only does the report ignore this impact of AB1890, but it also assumes that the amount of CTC to be paid by CCSF ratepayers might be different with municipalization. No persuasive argument has been presented anywhere in this report in this respect -- although references to CTC appear throughout the report, often in improper context.

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[2] Although following the CTC recovery period, it is unlikely that there will be a difference in the cost of energy supplies for an IOU vs. a municipal; see item #7, "Energy Supply Issues".

Response: *In the revised report, we have stated clearly (see introduction and summary to chapter 2; also, this important concept is revisited in chapter 6) the importance of AB 1890 in reducing PG&E's power supply costs. We also go to great lengths to point out that any differences between PG&E, the municipal electric utility and the "market price" of power supply after the implementation of restructuring is expected to be minor. This comment contradicts itself in referring to this "omitted fact" and then recognizing that we have included this important matter in our calculations. As to Staff comments on the particular characterization of AB 1890, we have written the new draft report with these comments in mind.*

a. On p.2, the report states that stranded costs of PG&E generation resources is likely to be a minor issue with respect to the municipalization decision. This seems an inappropriate assumption given the magnitude of estimated stranded costs which by law (refer AB1890) would have to be paid if a city municipalizes during the CTC recovery period (including post-2002) -- a significant cost not previously applicable to the municipalization decision.

Response: *The structure of the Draft report indicates this is clearly not an assumption, but a result of quantitative analysis. Page 2 is part of a chapter summary, and the material to which it refers in the body of the chapter shows clearly why stranded cost is a minor issue here: the passage of AB 1890, providing for CTC collection even under the muni scenario.*

b. On p.35, footnote 2, the footnote appears to present the authors' personal opinion with respect to the scope of CTC recovery allowed under AB1890. Since AB1890 has been signed into law, the authors' personal views on the appropriateness of CTC recovery is not a useful debate.

Response: *The footnote has been removed.*

c. Refer discussion under item #4.d. above which relates to incorrect interpretations about CTC on pp.97-100.

Response: *See our response above to this general comment (item 5).*

6. San Francisco Operating Criteria (SFOC) and In-City Generation. The important issue with respect to the Hunter's Point (HPP) and Potrero Power Plants (PPP) is the fact that these plants must be run to a certain extent due to transmission constraints and physical limits on the quantity of out-of-area power that can be delivered to the northern Peninsula. The long discussion on PG&E's San Francisco Operating Criteria (SFOC) on pp.48-50 is interesting but not relevant to the municipalization decision. The issue as to whether or not the City should purchase the HPP and PPP plants if it purchases the SF distribution system is relevant to the municipalization decision.

However, the detailed discussion about this subject on pp.63-67 and its application to the

study results are elusive. Further, CCSF/HHWP is currently active at both the FERC and CPUC in an effort to establish regulatory remedies for so-called "must-run" generation units to assure that system reliability is ensured and market power mitigated, irrespective of plant ownership. PG&E and the regulators have supported the City's comments. The report does not present or acknowledge the current position of the regulators with respect to this important issue which would render ownership of these in-City generation plants irrelevant to the municipalization decision. Or, put another way, the authors do not appear to understand that, under restructuring, issues regarding reliability of service to CCSF are separate from decisions about municipalization and distribution system ownership. If the authors believe CCSF acquisition or control of the Hunter's Point or Potrero plants could be less expensive under municipalization than the approaches PG&E and CCSF are now exploring at FERC and the CPUC (including PG&E's proposed Hunter's Point divestiture), they should state this conclusion clearly and explain the basis for their conclusion.

Response: We generally agree with these Staff comments, and the original draft report attempted to convey the same message. We have rewritten those sections dealing with the SFOC to insure that this message is clear. However, as to the Staff comment that "authors do not appear to understand that, under restructuring, issues regarding reliability of service to CCSF are separate from decisions about municipalization and distribution ownership," we do not agree. Our position is that the creation of municipal electric utility service territory raises the risk that the entire SFOC cost could be allocated directly to SF. We believe this is an important risk factor given the annual residual O&M costs associated with the SFOC.

7. Energy Supply Issues. As with other factors, the critical issue with respect to energy supply is: "Would energy costs be different with vs. without municipalization?" No persuasive argument is presented that this would be the case. Under Chapter 3, the authors argued incorrectly that there might be a difference due to "direct access", but the arguments were based on flawed assumptions and incorrect applications of electric restructure concepts (see item #4 above). The authors further argued that there might be a difference because of system reliability concerns and the San Francisco Operating Criteria (SFOC, see item #6 above). These arguments were also flawed and did not take into account the current regulatory positions regarding so-called "must-run" generation.

   Presently, PG&E is tied into expensive power supplies. By 2002, following restructure and CTC recovery, PG&E and the other IOUs will have recovered the majority of its stranded costs on uneconomic generation assets. It is unlikely that there will be a significant difference between IOU energy costs and those of a municipal utility in the newly competitive electric market.

   Further, it is widely known that available energy supplies are more than sufficient to serve the entire load in California. Consequently, the important issue with respect to the municipalization decision is whether there is a benefit to serving CCSF with HHWP power

vs. other power supplies. The authors unsuccessfully attempted to address these issues in Appendix 3-A, which is the only appendix staff has reviewed and will provide comments to herein.

Response: *We generally agree with Staff comments on this issue, and the original draft conclusions were generally in agreement with them. See Response to Staff item 5 above.*

a. The basic description of HHWP facilities and operations was not effectively presented. For clarification, the following are the important aspects of HHWP in context of the energy supply issue.

1) HHWP's primary mission is to protect the City's water supply. Consequently, HHWP's generation pattern depends upon hydrological conditions and water deliveries.

2) HHWP generation fluctuates significantly on a seasonal basis. During the runoff season (April through July), generation is at maximum capacity, approximately 400 MW. During the rest of the year, generation is significantly constrained by scheduled water deliveries, availability of generation units (most of HHWP's preventive maintenance is performed during summer and fall), and other factors. As a consequence, HHWP generation during summer and fall may range from 0 to about 200 MW, depending upon the time of day. Assuming a peak CCSF load of 900 MW, this means that HHWP generation is sufficient to meet 0-22% of CCSF's peak load during constrained operations, and 44% of CCSF's peak load during spring runoff. Winter generation depends upon hydrological conditions.

3) HHWP has a contract with PG&E to deliver up to 175 MW of HHWP generation to CCSF "municipal load". In addition, PG&E provides emergency back-up and other generation support services to HHWP.

4) HHWP also has power sales contracts with the Modesto Irrigation District (MID) and Turlock Irrigation District (TID), collectively "the Districts". These contracts provide a mechanism for scheduling sales of "Raker Act" power[3] to the Districts. These contracts also provide that an additional increment of power will be sold to the Districts for other uses on a

[3] I.e. power generated by HHWP plants which is sold to the Districts at cost for agricultural pumping and municipal public purposes (aka "Class 1 Power") as mandated by the 1913 Raker Act which granted the City rights-of-way to construct its water collection, conveyance and other facilities.

specified price formula. These contracts expire on June 30, 2015. However, the obligation under the Raker Act to provide Class 1 power at cost to the Districts continues indefinitely.

Response: In response to this comment, we have clarified this issue in the same discussion in the revised report.

b. The decision as to whether all available (i.e. non-Class 1) power should be dedicated to serve CCSF residents and businesses in event of municipalization should be based on an economic assessment.

1) Presuming the study assumption that municipalization could be implemented as early as 2002 is valid and the Districts' contracts are still in effect, the City would have to negotiate early termination of the contract with the Districts. The cost for such early termination, if any, cannot be reasonably estimated at this time.

2) More significant would be an assessment of the "opportunity cost" or the value of the opportunity "foregone" if HHWP were not to sell power to the Districts. Obviously, Class 1 power cannot be considered, since the provision of such Class 1 power to the Districts is a regulatory requirement and there is no profit earned on such sales. However, to the extent that the City earns a margin on sales of non-Class 1 power to the Districts, the heart of the issue is the expected impact on City net revenues if the City chooses to offset energy purchases to meet its load obligations with HHWP power rather than buying these energy supplies in the competitive market. This concept is touched upon in Appendix 3-A, but not clearly presented.

Response: In response to this comment, we have clarified this issue in the same discussion in the revised report.

c. Throughout Appendix 3-A, as it was throughout Chapter 3, there are incorrect statements and misapplied concepts. Both the discussion on spinning reserves and the reference to Seattle City Light (missing page numbers) as evidence that it would be possible for HHWP to provide spin for the entire CCSF load are invalid. The report fails to explain that Seattle City Light is integrated with the rest of the Pacific Northwest electric grid -- an essential characteristic which is not present for CCSF which is in a transmission constrained area and is not integrated with the California electric grid. Further, spinning reserve is not a significant cost and thus not a relevant issue in context of the municipalization decision.

Response: We disagree with this characterization of the Seattle situation, which we investigated, but the point is moot, for we have eliminated this discussion from the revised as not essential.

d. What is the basis for the statement on p.139 that "... the presently available supplies of low-cost firm power might dry up very soon." ?

Response: This statement has been eliminated from the revised report.

8. Miscellaneous Items.

a. In Chapter 4, Section B. "Other Economic & Public Policy Issues Affecting Municipalization" would be more appropriately treated under Chapter 5, "Other Factors Affecting Municipalization".

Response: The section was included in this chapter because it fell under the scope of work on which this chapter reports.

b. That portion of Appendix 3-A that relates to HHWP energy should be integrated into the body of the report. That portion of Appendix 3-A that discusses "Direct Access Prices" is incorrect.

Response: We have integrated the description of HHWP energy into the body of the report in the new draft report.

c. That portion of Appendix 3-A in which an "annotated digest" of AB1890 has been provided is irrelevant to the scope of this study. To the extent that certain sections of AB1890 are relevant to the municipalization decision, they should be specifically called out and described under Chapter 6. Staff has not reviewed the "digest" for accuracy.

Response: We agree and have eliminated this appendix. Key features of AB 1890 as they impact the municipalization question have integrated into the body of the report.

d. The "Time Table: Major Milestones, ..." in Chapter 5 should provide ranges of estimated costs, explain the bases for the ranges of estimates, and include these costs in the cost/benefit portion of the report.

Response: We have done so in the revised report.

e. The suggestion in Chapter 5 (p.131) that the City could undertake the role of power marketer or broker as an "alternative to full municipalization" 1) presumes that the City would be better at securing lower energy prices than any other power marketer or broker, and 2) again confuses the concepts of direct access, load aggregation, and marketer/brokers.

Response: The revised report states that marketing and brokering, etc. by The City is not contingent on municipalization.

f. The statement on p.131 that "PG&E is limited by its size relative to the amount of direct access power available on the market." does not seem to have any validity. (What is the point being made?)

Response: This statement has been deleted from the revised report.

g. The statement on p.132:

> "If DSM were able to reduce a significant portion of the in-city generation requirement, it would back out the high cost Potrero/Hunters Point generation."

is questionable given the fact that local generation is required to support about 35% of the total CCSF load.[4]

Response: We did not want to overstate the potential of DSM in reducing in-city generation. We agree that the statement in the original draft was too broad and have addressed this issue in the revised report.

h. The "opt-in/opt-out" argument presented on pp.132-133 is not substantiated. In addition, the write-up on p.133 continues to perpetuate the incorrect treatment of the concept of direct access as a power supply. (See discussion under item 4.a. above.)

Response: See the response to item 4 above.

9. Grammatical & Typographical Errors. There are spelling, grammatical and typographic errors throughout the report.

Response: We have attempted to rectify this matter in the revised report.

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[4] Refer PG&E FERC Form 1 dated 04/29/96 for calendar year 1995; in-City generation exceeded 1.75 million MWH, about 35% of the total load of the City. Assuming imports of energy are maximized to fully utilize the transmission capacity at San Mateo Sub, in-City plants would still be needed to support approximately 350-500 MW of CCSF load during peak use periods. It is thus highly unlikely that the City's DSM potential could obviate the need for running the Hunter's Point and Potrero Plants.

Responses to Questions by

SFPUC Commissioners (Two Sets),

to Comments by Joel Ventresca & APPA

on the Final Draft of the Report &

ETAG Memos re: Changes

& a Minor Correction

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MEMORANDUM

TO: SFPUC Commissioners via Messrs. Klein & Moran

FR: Ron Knecht & Ray Czahar, ETAG -14 January 1997

RE: Our Answers to Vice-President Makras's Questions from the 7 Jan. 1997 Meeting on Our Municipalization Report

Q.1. Could you itemize, one, what the 5.6 income-tax savings is and the dollar amount. And also what that would mean on a bill to the customer?

A.1 5.6% x $3.315-billion (page ES-3) = $186-million (30-year present worth of annual federal and state income-tax savings on PG&E's equity returns).

$19.9-million is the first-year amount -- and equivalent amounts in subsequent years.

On a typical residential-customer monthly electric bill of $75.00, the 5.6% savings would be $4.20 (= 5.6% x $75.00).

Q.2. Then on a dollar amount, could you tell me what the dividends are, and also how that affects the ratepayer?

A.2 Total common-stock dividends declared by PG&E in 1995 were $829,828,226, which under CPUC ratemaking is not allocable in a manner that would allow us to determine a typical customer bill effect. The dividends, per se, do not affect the ratepayer. What affects the ratepayer is the total earning on equity (including dividends and retained earnings) -- and more especially the difference between the total earnings level and the alternative financing costs, here, 7.5%. The weighted average net cost of capital is 9.45% for PG&E. So, with 7.5% bonds, the equity premium is 1.95%. As stated in the report, the 1.95% equity premium leads to a 1.96% difference in the rates (page 4-22). These numbers would be applied either

to total present worth or to typical bills. Thus, the expected PW effect would be 1.96%x $3.315 billion = $65-million, and the typical monthly bill effect (expected) would be 1.96% x $75.00 = $1.42.

Q.3. Could you itemize and give me a list of all salaries over $140,000, and I want that salaries to include bonuses, options in stock or anything else that's taxable -- that's money.

A.3. The attached pages from PG&E's annual report to the CPUC and FERC provides all publicly available data on PG&E individual executives' compensation. It covers that seven highest-paid individuals, and the seventh has a total package of $341,911 in 1995. The top 1995 compensation package was $1,165,663. Almost certainly, there are more packages above $140,000 but is no public information on them. Our allowance for A&G expense implicitly assumes a electric utility manager with an annual total compensation in the range of $120,000 to $130,000 -- so there would be no savings for SF electric ratepayers from avoiding PG&E executive salaries that are not already reflected in our analysis.

We note that we previously inadvertently misstated the current CPUC ratemaking practice regarding executive compensation. The CPUC has switched from a dollar cap (about $100,000 in salary) to a cap based on a survey of other utilities. As we understand it, the latest total executive-compensation survey shows that PG&E's compensation levels are below the market rate.

Q.4. You state on page 7 that you have a base case of $795-million and a range up to a billion dollars, and then your line number 3 says, PG&E likely to claim a higher value. Could you tell me what you think their value is, or if they've ever made a public statement as to what they feel it's worth, so we know what your telling us and we know what they're saying.

A.4. In 1982, PG&E stated a RCNLD value of $795-million, as stated on page 2-42 of the report. Escalating this value at 3.5% during 1982-1996 and at 2.5% during 1997-2001, yields a year-end-2001 value of $1.456-billion, merely by adjusting for general inflation-- or 46% above our own $1-billion estimate.

Q.5. Then, if you could make a comparison of some sort that, should we take over PG&E, and we have to float the cost of it with interest, give us the cost of year number 1 at prevailing rates then give us the cost of the bonds should we refinance and lower it because we will now be City-owned -- the reduction so we can calculate year 1 cost of taking over and then the reduction should we refinance and pay all those bonds off, because our costs would drop.

A. 5. The first-year muni interest costs would be $60,389,173, and the second-year muni interest

costs would be $59,419,060, according to page 4-32,-- both at 7.5% interest. If the second-year figure could be reduced to 6%/annum by tax-free refinancing, that savings would be $59,419,060 x [(7.5%-6.0%)/7.5%] = $11,883,812. In our judgement, such immediate refinancing may raise income tax issues that could result in no net savings to ratepayers.

1995
ANNUAL REPORT

of

Pacific Gas and Electric Company
77 Beale Street
P.O. Box 770000, B7C
San Francisco, CA 94177

to the

Public Utilities Commission
of the
State of California
for the year ended December 31, 1995

Volume No. 1

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< Page 104 Line 1 Column a >

SUMMARY COMPENSATION TABLE

[This table summarizes the principal components of compensation of PG&E's highest paid executive officers in the past year.]

(A)	(B)	Annual Compensation (C)	(D)	(E)
Name and Principal Position	Year	Salary($)	Bonus($)(1)	Other Annual Compensation ($)(2)
Richard A. Clarke, Former Chairman of the Board(5)	1995	$269,167	$196,408	$44,788
	1994	680,000	165,620	45,266
	1993	640,000	143,070	40,950
Stanley T. Skinner, Chairman of the Board and Chief Executive Officer	1995	$570,000	$471,380	$33,543
	1994	550,000	134,173	26,193
	1993	475,000	88,760	20,678
Robert D. Glynn, Jr., President and Chief Operating Officer	1995	$338,333	$229,437	$21,154
	1994	244,000	50,817	18,235
	1993	198,000	38,790	19,472
James D. Shiffer, Executive Vice President	1995	$320,000	$175,824	$21,034
	1994	310,000	61,776	22,421
	1993	265,000	53,340	24,282
Gregory M. Rueger, Senior Vice President and General Manager, Nuclear Power Generation Business Unit	1995	$240,500	$120,034	$18,132
	1994	240,500	39,858	16,898
	1993	233,000	149,100	19,227
Gordon R. Smith, Senior Vice President and Chief Financial Officer	1995	$207,000	$130,535	$17,603
	1994	207,000	39,858	14,733
	1993	195,000	27,700	16,338
Bruce R. Worthington, Senior Vice President and General Counsel	1995	$207,000	$106,461	$10,273
	1994	190,980	19,445	0
	1993	172,620	21,616	0

(Continued on the next page)

Page 104 Footnote.1

		Long-Term Compensation		
		Awards	Payouts	
(A)	(B)	(F)	(G)	(H)
Name and Principal Position	Year	Securities Underlying Options/SARS (# of Shares)	LTIP Payouts ($)(3)	All Other Compensation ($)(4)
Richard A. Clarke,	1995	25,000	$ 44,800	$142,228
Former Chairman of	1994	25,000	54,056	43,920
the Board(5)	1993	25,000	370,488	42,238
Stanley T. Skinner,	1995	25,000	$ 34,720	$ 31,020
Chairman of the Board	1994	15,000	33,785	56,860
and Chief Executive Officer	1993	15,000	203,768	37,757
Robert D. Glynn, Jr.,	1995	10,000	$ 16,986	$ 23,312
President and Chief	1994	7,500	17,120	13,960
Operating Officer	1993	7,500	98,772	11,389
James D. Shiffer,	1995	10,000	$ 17,920	$ 15,420
Executive Vice	1994	10,000	21,622	33,130
President	1993	10,000	135,858	33,357
Gregory M. Rueger,	1995	7,500	$ 13,440	$ 11,573
Senior Vice President	1994	7,500	16,217	11,596
and General Manager, Nuclear Power Generation Business Unit	1993	7,500	111,146	11,242
Gordon R. Smith	1995	7,500	$ 11,944	$ 9,925
Senior Vice President	1994	7,500	12,611	9,926
and Chief Financial Officer	1993	5,000	74,098	11,073
Bruce R. Worthington,	1995	5,000	$ 3,862	$ 9,315
Senior Vice President	1994	3,000	0	10,586
and General Counsel	1993	3,000	0	8,120

(See the next page for notes)

(1) Represents payments received or deferred in 1996, 1995, and 1994 for achievement of corporate and organizational objectives in 1995, 1994 and 1993, respectively, under the Performance Incentive Plan.

(2) Amounts reported consist of (i) officer benefit allowances, (ii) payments of related taxes, and (iii) dividend equivalent payments on performance units under the Performance Unit Plan.

(3) Represents payments received or deferred in 1996, 1995, and 1994 for achievement of corporate performance objectives for the period 1991 through 1995 under the Performance Unit Plan.

(4) Amounts reported for 1995 consist of: (i) PG&E matching contributions to the Savings Fund Plan (Mr. Clarke $6,750, Mr. Skinner $6,750, Mr. Glynn $6,750, Mr. Shiffer $6,750, Mr. Rueger $6,750, Mr. Smith $6,750, and Mr. Worthington $6,750); (ii) PG&E-paid premiums on indemnity policies to secure the payment of benefits under the Supplemental Executive Retirement Plan and the Deferred Compensation Plan (Mr. Clarke $13,320, Mr. Skinner $5,370, Mr. Glynn $780, Mr. Shiffer $1,020, Mr. Rueger $750, and Mr. Smith $610); (iii) payments received in lieu of vacation (Mr. Clarke $116,795 and Mr. Glynn $7,307); and (iv) amounts received or deferred under the Savings Fund Plan excess benefit arrangement (Mr. Clarke $5,363, Mr. Skinner $18,900, Mr. Glynn $8,475, Mr. Shiffer $7,650, Mr. Rueger $4,072, Mr. Smith $2,565, and Mr. Worthington $2,565).

(5) Mr. Clarke retired as Chairman of the Board on June 1, 1995.

AG Officers Salaries -- Comparison between PG&E and CCSF Muni Elect.

FERC Page 487		Total Salary Wages Comm	Number	Average
General Officers - Electric ?		$7,022,307	21	$334,396
Customers Electric		4,500,000		
Average Per Customer		$1.56		
CCSF MUNI Customers		350,000		
Allowance for CCSF Muni		$546,179		
General Manger	$135,000			
Asst Gen Manger	110,000			
Subtotal	245,000			
Engineering & Planning	90,000			
Legal (1/2 time)	45,000			
Customer Services Dir	90,000			
Financial Services	75,000			
Subtotal	300,000			
Total	$545,000			

* ? Not clear this is 100% Electric Dept

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MEMORANDUM

TO: SFPUC Commissioners via Messrs. Klein & Moran

FR: Ron Knecht & Ray Czahar, ETAG -31 January 1997

RE: Your Questions from the Last Meeting on Our Municipalization Report

1) Commissioner Makras asked that the report be revised to reflect total annual dollar savings and monthly customer-bill impacts, which we provided orally in answer to his request at the 14 January meeting.

These figures are being incorporated into the Executive Summary to highlight them for decision-makers and the general public and to provide insight into the impact of the municipalization decision.

2) Commissioner Makras asked that sources be given in the report, so that it will be clear which items reflect ETAG's conclusions, data from PG&E or other sources, and matters of fact versus opinion.

As explained at the 14 January meeting, we are unaware of any items undocumented in these regards in the body of the report, and we made continuing efforts to assure that each item has been clearly and thoroughly documented. This issue was raised a few times in the review process, and on the one or two occasions in which an example was offered of a purportedly undocumented item, it turned out that the item was taken either from the Executive Summary or the chapter summaries -- and further that, from the context, it was generally clear where in the body the information originated, and that the item was documented in the body of the report. In response to the Commission's concern, we have revised all summary sections (nearly each page of them) to add a number of explicit references to the body of the report in order to avoid the impression of undocumented or unclear items. We continue to solicit specific references to any items that may be wanting in this regard, so that we may improve them.

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3) Commissioner Makras asked for information on interlocking business and other relationships between PG&E Directors and executives with other firms and institutions, as well as compensation information on those Directors and executives.

The only systematic public information of which we are aware on interlocking relationships is that found in PG&E's identification of its Directors' affiliations in its Annual Report to stockholders (pages attached). The only publicly available data on compensation is that reported in it's Annual Report to the CPUC and FERC, which was provided in answer to a previous question from the Commissioner. Beyond those observations, the matter appears to lie outside the scope of work for this project.

4) Commissioners Otsea and Werbe were concerned that some tables in the Workpapers volume were printed in type too small to be reasonably readable.

We apologize for this problem (which did not extend to the main report), and we have produced replacement pages for these tables which are much more easily read.

5) Commissioner Werbe requested further explanation of our answer to a previous question that dividends do not affect ratepayers.

As Commissioner Werbe pointed out, some part of the bills that PG&E ratepayers pay goes to fund the company's dividends; we never suggested to the contrary, for we know this fact. But this fact is not dispositive, for two reasons. First, only PG&E's Board -- not the CPUC, CCSF, nor any other entity -- has control over PG&E's dividend-payment policies (within certain irrelevant legal and financial limits). Second, PG&E's rates are set by the CPUC on the basis of the total return allowed on the company's equity (a/k/a its allowed accounting profit), not on the basis of a utility's dividend yield. The total return is, by definition, divided into dividends and retained earnings. If a dollar of PG&E's total return is not paid out in dividends, then it automatically accrues to retained earnings. But what the choice not to pay the dividend does not do is in any way reduce the rates, because they are determined by the total rate of return allowed on equity. Regulated ratemaking is almost never predicated on dividend policy and almost always (even when dividend issues are acknowledged directly in setting rates) is based on total returns, as we have described the CPUC does for PG&E. As long as that is the case, rates paid will fund dividends, but dividend cuts will only increase retained earnings, not cut rates.

Please note also that, when we estimate rates for CCSF municipalized electric service, we do so on the basis of The City's cost of service, which does not include any dividends to stockholders. Thus, this matter is already factored into our analyses.

6) Commissioner Werbe asked, in connection with a question he put to us at the previous meeting, whether ratepayers compensate PG&E for its depreciation accruals.

As we stated at the 28 January meeting, rates are set by the CPUC to require ratepayers to cover depreciation. The question at the 14 January meeting was whether PG&E ratepayers pay for a higher level of depreciation over time than the original cost of an asset, and we explained that they do not. The suggestion was that PG&E's rates continue to reflect the depreciation accruals on a given asset even after it has been fully depreciated (i.e., that they pay for it many times over), and we explained that they do not. There is no inconsistency or other problem between these answers. Both answers reflect the fact that, under cost-based rates, IOU ratepayers pay exactly for the original cost of the asset.

7) Commissioner Makras suggested, based on our answer to one of his previous requests, that a year's worth of PG&E dividends would buy the system. Further, he asked: If SF takes over PG&E's local electric-distribution system and implements a simple dividend return, how many years would it take to pay off the system?

As stated at the 14 January meeting, PG&E's company-wide total dividend could be allocated after the fact in various ways to get an amount allegedly associated with SF electric-distribution operations, but such a figure is of limited use and precision. A reasonable allocation of the $830-million to SF electric operations would be less than $15-million, when escalated to 2002. This is derived by allocating 1.5% of the $830-million total 1995 dividend to PG&E's SF electric-distribution service, because that reflects the percentage of its total company net assets invested in SF's electric distribution system ($262-million of $17.487-billion in 1995). Then the $12.45-million of dividends thus allocated to SF electric-distribution service (= 1.5% x $830-million) should be escalated at the 2.5% annual inflation rate to 2002 to get $14.8-million (= $12.45 x 1.025**7), or slightly less than $15-million. This $14.8-million would be 4.38% of the $337.9-million PG&E revenue from its SF service in 2002, per our base case (Table 4-4, page 4-32). Thus, considering the dividends related only to the SF electric-distribution system, it would take nearly 23-years'-worth of dividends to buy the system, not just one-year's-worth. (I.e., 1/.0483 = 22.8.) Thus, the payback period is 22.8 years.

For purposes of this study, we think the foregoing paragraph offers the most meaningful allocation of the dividend, but there is another way. That way is to allocate some part of the PG&E generation and transmission (G&T) to SF, too. This approach, executed below, is less useful for this project because, even though San Franciscans pay rates that cover dividends allocable to the G&T assets, under the state's electric-industry restructuring they will still pay the same level of rates to fund

CCSF purchases from the power exchange. That is, they will still make the same level of implicit G&T dividend contribution because the PX buys the same power from PG&E and makes the same payments to it, regardless of whether the power is sold to SF customers through a PG&E-owned distribution system or one owned by CCSF. Hence, in terms of the rest of this question, involving the effect of eliminating the dividend via municipalization, the idea can't be achieved. Nonetheless, to provide an estimate of the maximum total PG&E dividend amount that could be allocated to SF electric service, we start again with the $830-million annual company-wide total, and allocate it first to electric service, using the fraction of total capitalization ($17.487-billion) invested in net electric assets ($13.227-billion, per PG&E's 1995 FERC Form-1, pp.205-207), or 75.6%. Next, we allocate this $628-million (=$830-million x 75.6%) to SF using the fraction of PG&E's 1995 electric sales to customers (75,359 GWH, p.1 of PG&E's Annual Report to Stockholders) sold to SF customers (4,503 GWH, p.2-26 of our report), or 6%. Thus, the 1995 total is $37.5-million, which escalated at 2.5%/year to 2002 would be $44.6-million (=$37.5-million x 1.025**7). This amount is 13.2% of the $337.9-million PG&E revenues expected in 2002 from SF (Table 4-4, p.4-32), and thus a payback period based on this amount would be 7.6 years (=1/.132), still much greater than a year's-worth of dividends.

If one considers dividend elimination as a way of purchasing the system, then note the following. Municipalization would allow SF ratepayers to avoid paying $14.8-million that funds PG&E dividends, but it would require them to pay even more in interest charges that CCSF must pay to finance the takeover. The reason is that CCSF's interest-cost per dollar financed is almost as high as PG&E dividend rate, and CCSF must finance more dollars for the takeover than PG&E's rate-base (net asset) value for the SF system. As shown in section 2.F, CCSF would pay interest at 7.5% per dollar financed. With PG&E's 11.6% allowed return on common equity, its 65.55% dividend payout ratio in 1995 ($1.96/share dividend v. $2.99/share earnings), its 7.04% preferred dividend rate, and its 46.2% debt/ 5.8% preferred / 48% common capital structure, PG&E annual dividend payout per dollar of equity is $0.0754321 (= [.6555 x .116 x .48 + .0704 x .058] / [.48 + .058]), or 7.54321% -- just slightly greater than CCSF's debt interest rate. The portion of PG&E's rate base that is financed with debt costs it the same interest rate (7.5%) as CCSF's debt would cost it; hence the cash payout per dollar financed is less than one-half of one percent (0.5%) different for the two options. However, CCSF would have to finance the entire acquisition cost of $795-million (base case; or whatever figure a court ordered), as compared to the $315-million OCLD for PG&E's SF system in 2002 (i.e., its beginning-of-year rate base). Thus, while the per-dollar amounts are the same, the number of dollars financed is 2.52 times as high and the net effect is that The City would actually have offsetting costs of 2.5-times each dollar it saves by avoiding PG&E's dividends and interest payments allocated to the SF electric-distribution system. Even if The City could somehow finance the take-over with tax-exempt debt

(which, as explained below, we think it cannot do), then the per-dollar costs would be only 20% lower (6% instead of 7.52%) and the total financing costs paid under the muni option would be twice what they are for PG&E service.

Note also that our analysis of the muni option, consistent with standard practice, is based on CCSF setting rates based on its costs of ownership and other costs of service for the SF electric system. Thus, as stated at pages 3 and 7 of the Executive Summary, the rate reductions we estimate are those that accrue even as The City is paying off the acquisition of the system. Using the standard muni ratemaking approach, as discussed at page 4-27, the payback period for SF electric municipalization is three or four decades -- i.e., beyond the range of reasonable detailed projections.

8) Commissioner Makras asked about the effect of executive salaries and bonuses on SF ratepayers.

The annual bill for SF electric customers is about $480-million. PG&E senior-executive compensation totals just over $7-million for 21 positions (FERC Form-1, page 487). Allocating this 80% to electric (roughly proportional to revenues and capital) and then by total customers to SF (335,000 of 4.4-million), the SF electric portion of this compensation is about $427,000 -- or less than one-tenth of one percent of the total. Thus, if somehow SF electric ratepayers could be spared the entire effect (with no substitute effect), they would save about six cents ($0.06) on a typical monthly electric bill of $75.00.

While individual CCSF senior-executive salaries would surely be lower than PG&E's, there would also be a smaller customer, energy and services base over which to spread them. This point applies to senior-executive salaries, as well as other salaries for PG&E personnel that exceed CCSF's salary cap. Thus, even using The City's salary cap, the 0.1% allowance is about what CCSF would have to pay in its own executive salaries; in fact, such an allowance might not be enough -- and in that case, the net effect of avoiding PG&E's senior-executive salaries might be a higher cost for equivalent services for SF ratepayers.

9) Commissioner Makras asked about the effects of tax-exempt financing on electric bills.

As discussed in our answer to a question previously put by Commissioner Makras, the second-year savings could be as much as $11,883,812 in our base case if complete re-financing could be done to replace all the taxable-interest debt which would be required to finance the takeover. This refinancing would yield a further rate decrease in the second year of 3.36%, and the percentage would decline in subsequent years.

On a typical monthly bill of $75.00, the savings would be $2.52. We caution that under existing tax law such extensive refinancing would almost certainly not be possible.

10) Commissioner Makras asked about the effects of taxes that PG&E pays that are passed on to SF ratepayers.

As discussed in our report (e.g. Table ES-1), the main effect would be a 5.6% rate reduction due to the avoidance of state and federal income taxes. In the first-year base-case estimates, this totals $18.9-million city-wide, and the effect on the $75.00 typical monthly residential bill is a $4.20 reduction, as we noted. As we have also noted in chapter 4, municipalization would have no net effect on San Franciscans as a group with respect to local franchise, property and payroll taxes.

11) Commissioner Makras asked about political contributions made in SF and CA by PG&E.

This item appears to be outside the scope of work, and we are unaware of any source of public information that reports this item on a statewide basis. However, we will check with the City Ethics Commission to seek information on this item in SF. Under CPUC ratemaking, these costs, we understand, are charged to stockholders and may not be billed to ratepayers.

12) President Normandy wants to assure that the report is "cogent, comprehensive, comprehensible and deeply rooted in logic and economics".

We agree completely, and we have been working hard throughout toward that goal. We believe that a fair reading of the Executive Summary and entire report shows that it very much meets this test.

13) Responses to Joel Ventresca and the American Public Power Association (APPA).

Mr. Ventresca submitted 15 pages of comments, and we are have prepared specific answers to each of them, already totaling 40 pages, including his comments. As we stated at the meeting, most of these items have been answered before, usually orally at TRC meetings. Information and sources are still coming in from APPA, and we have reviewed that which we have received and prepared a detailed response to its comments.

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Vice Chairman, AirTouch Communications and President and Chief Executive Officer, AirTouch Cellular

William S. Davila
President Emeritus, The Vons Companies, Inc. (retail grocery)

Robert D. Glynn, Jr.
President and Chief Operating Officer, Pacific Gas and Electric Company

David M. Lawrence, MD
Chairman and Chief Executive Officer, Kaiser Foundation Health Plan, Inc., and Kaiser Foundation Hospitals

Richard B. Madden
Chairman of the Board and Chief Executive Officer, Retired Potlatch Corporation (diversified forest products)

Mary S. Metz
Dean of University Extension, University of California, Berkeley

Rebecca Q. Morgan
President and Chief Executive Officer Joint Venture: Silicon Valley Network (nonprofit collaborative formed to address critical issues facing Silicon Valley)

Samuel T. Reeves
President, Pinnacle Trading, LLC (international investing)

Carl E. Reichardt
Chairman of the Board and Chief Executive Officer, Retired Wells Fargo & Company and Wells Fargo Bank, N.A.

John C. Sawhill
President and Chief Executive Officer, The Nature Conservancy (international environmental organization)

Alan Seelenfreund
Chairman of the Board and Chief Executive Officer, McKesson Corporation (distributor of pharmaceuticals and health care products)

Stanley T. Skinner
Chairman of the Board and Chief Executive Officer, Pacific Gas and Electric Company

Barry Lawson Williams
President, Williams Pacific Ventures, Inc. (venture capital and real estate, consulting, and mediation)

Permanent Committees of the Board of Directors

Executive Committee

Within limits, may exercise powers and perform duties of the Board.

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Harry M. Conger
Robert D. Glynn, Jr.
Richard B. Madden
Mary S. Metz
Carl E. Reichardt

Audit Committee

Reviews financial statements and internal accounting and control procedures with independent public accountants.

Harry M. Conger (Chair)
C. Lee Cox
William S. Davila
Mary S. Metz
Rebecca Q. Morgan
Barry Lawson Williams

Finance Committee

Recommends long-range financial policies and objectives, and actions required to achieve those objectives.

Richard B. Madden (Chair)
Richard A. Clarke
Carl E. Reichardt
Stanley T. Skinner
Barry Lawson Williams

Nominating and Compensation Committee

Recommends candidates for nomination as directors, recommends compensation and employee benefit policies and practices, and reviews planning for executive development and succession.

Carl E. Reichardt (Chair)
David M. Lawrence, MD
Samuel T. Reeves
John C. Sawhill
Alan Seelenfreund

Public Policy Committee

Reviews public policy issues which could significantly affect customers, shareholders, employees, or the communities served, and recommends plans and programs to address such issues.

Mary S. Metz (Chair)
Richard A. Clarke
William S. Davila
Robert D. Glynn, Jr.
John C. Sawhill

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Pacific Gas and Electric Company

PG&E Officers

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Warren H. Fujimoto
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Anthony Harris
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Vice President Customer Services

Steven L. Kline
Vice President Regulation

Thomas C. Long
Vice President Customer Information Systems

E. James Macias
Vice President and General Manager Electric Transmission Business Unit

William R. Mazotti
Vice President Gas Services and Operations

Jackalyne Pfannenstiel
Vice President Corporate Planning

James K. Randolph
Vice President Power Generation

Robert D. Testa
Vice President Governmental Relations

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Leslie H. Everett
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Eric Montizambert
Assistant Corporate Secretary

Kathleen Rueger
Assistant Corporate Secretary

Gabriel B. Togneri
Assistant Treasurer

Chief Executive Officers of Principal PG&E Subsidiaries

Tony F. DiStefano
Chairman, Chief Executive Officer, and President PG&E Enterprises

Stephen P. Reynolds
President and Chief Executive Officer Pacific Gas Transmission Company

Chief Executive Officers of Principal PG&E Enterprises Subsidiaries and Related Ventures

Earl H. Franklin
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Joseph P. Kearney
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Carlos A. Riva
President and Chief Executive Officer International Generating Company

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Note: Mr. Ventresca's comments, as submitted in writing on 17 January 1997 (based on his comments at public hearing on 14 January), are first reproduced in Times New Roman text, with item numbers added, and then ETAG's responses follow in italics.

Joel Ventresca
Chair, San Franciscans for Public Power
Member, PUC Technical Review Committee

Statement Before the Public Utilities Commission on January 14, 1997 Regarding the ETAG Report

Introduction

1) PG&E's electrical rates are often the highest in the state or nation. PG&E has reliability problems, even with moderate storms, and is in the process of passing on $10 billion in extra costs to consumers over the next five years for the Diablo Canyon nuclear power plant, which provides 16% of the electrical energy San Franciscans consume.

Response: This statement errs in factual and other ways. As one example, while it's true that the Diablo Canyon plant has proven to be uneconomic (as predicted in testimony filed over a dozen years ago by Mr. Knecht for the CPUC staff), the amount of excess costs over the next five years is well below $10-billion. According to PG&E financial and statistical reports that must be filed quarterly, the total cost to ratepayers in the most recent recorded 12 months (a representative year) for Diablo Canyon energy was $1.612-billion, for 14.83-billion kWh, or 10.87 cents/kWh. Even assuming that 8 c/kWh was excess (i.e., that the power is worth only 2.87 c/kWh, well within the current market range), the annual excess cost is just over $1.186-billion, and thus the five-year total would be just over $5.9-billion -- i.e., less than 60% of the level Mr. Ventresca claimed. As another example, while PG&E's rates are high (as the ETAG report details), they have never been the highest.

2) Public power can bring lower rates, greater reliability, and non-nuclear energy sources to the City.

Response: ETAG's report shows that municipalization can lower rates, and it quantifies the effect rigorously. Mr. Ventresca cites no basis for the reliability claims, and the AB1890 restructuring of the electric-power industry, together with CPUC regulation of PG&E, precludes any difference in transmission- and generation-related reliability that is not at least fully offset by higher costs. The claim about nuclear reliance is vacuous and misleading, for PG&E service can and does provide a blend of nuclear, hydro, thermal and "green" resources, just as will the power exchange, from which CCSF would buy under electric-industry restructuring. As a result of restructuring, muni service will not reduce the reliance of California or SF on nuclear resources, relative to IOU service.

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As for distribution-related reliability, the distribution system involved would be the same, and only its ownership and operator would be different. A recent report by Resource Management International for APPA concludes: "Although this limited comparison [i.e., the evidence it reviewed] may not be used to generalize that most public power systems are more reliable than investor-owned utilities, the results strongly suggest that is the case." The report explains that differences are due to geography and climate conditions, service territory density impacts and probably service territory size. Because it did not make any analyses at all of these impacts, nor any adjustments for them in the national-average reliability measures for IOUs and publicly owned systems, "this limited comparison may not be used to generalize that ..." In sum, even this APPA study is unable to cite any evidence that would show that a change in ownership and operator of the SF electric-distribution system from PG&E to CCSF would make any reliability difference.

3) Public power utilities provide electricity at lower cost and greater efficiency than private investor-owned utility monopolies. There are 2000 public power systems throughout the United States. One hundred cities are currently exploring the public power option.

Response: *This statement contains another factual error: ETAG's study shows that munis provide lower rates, due mainly to exemption from income taxes, but they are not more efficient (and, if any systematic difference is discernable in the data, they are less efficient – although we do not make that claim). The statement's reference to IOU monopolies and its failure to note that publicly-owned utilities are also monopolies (and thus heir to the same kinds of problems and in the same degree) reflects, when taken in light of similar biased statements throughout these comments, partisan bias, not serious analysis. Our report noted that a number of cities have explored municipalization in recent years, but none of them are on the verge of doing it.*

Analysis

4) The ETAG report has fundamental and significant problems.

Response: *This statement is completely in error, as the responses here show. There are no fundamental or significant problems, except that Mr. Ventresca continues to repeat his errors, even after the errors have been pointed out in public in his presence. Some of his errors have been corrected on paper in the response to the TRC comments included at the end of the workpapers volume, and more have been corrected in TRC sessions. In fact, we have also listened to many of these points from him by telephone and corrected them before he even brought them out at TRC meetings He has not recognized or attempted to answer the specification of his errors, but merely repeated them as if no rebuttal had been made.*

5) ETAG base their conclusions on an analysis of a theoretical electrical industry that does not exist and may not exist in the future. Restructuring and deregulation rules, which are evolving, are subject to change before, during, and after implementation at the state and federal level of government.

Response: *Most of the analysis in the report involves the economics to ratepayers of local distribution systems ownership, and that is almost completely unaffected by the restructuring, etc. The basic conclusions would be unchanged in areas other than bulk-power supply, regardless of the assumptions made about restructuring. The use of "theoretical" obscures the facts that state law (AB1890) has mandated the changes assumed in ETAG's report and FERC, the CPUC, utilities and the rest of the industry are already implementing them. This criticism fails to state what alternative structure should be assumed; in view of the progress to date in restructuring matters, ETAG made the only reasonable assumptions concerning bulk-power costs. Further, this criticism ignores the RFQ's requirement that the report incorporate as much as possible the current trends and developments in the industry.*

6) ETAG conducted a cost benefit analysis with the costs being exaggerated and the benefits being misrepresented or ignored.

Response: *This criticism lacks factual basis and is completely false. Mr. Ventresca does not even attempt to provide an example, let alone two or three, to give any substance to the claim; instead, it merely launches a rhetorical attack by making an unsupported claim.*

7) Little to no information about municipalizations in other states is included in the study.

Response: *This statement is false, as shown in ETAG's report and reflected in ETAG's TRC presentations on it, which Mr. Ventresca attended. First, as ETAG's report pointed out, there have been no significant municipalizations in the last two decades -- certainly not on a scale within an order of magnitude of SF -- but the wording of the criticism implies wrongly that there is some such relevant experience. Second, the study extensively reviewed experience from other states. In fact, it exceeded the statement of work in this regard, and as a result much of this information was moved into the workpapers volume, at staff's request, to keep the report from getting bogged down in material of only tangential relevance. Third, the study points out, from our review of municipalization experience and muni/IOU comparisons in California and other states, that these generic comparisons do not provide significant insight into the economics for SF. That is why the ETAG feasibility study was appropriate (instead of a literature review, etc.) and why ETAG allocated its resources in this project to the local analysis. If ETAG's report errs at all in this matter, it does so by being too expansive on the experience elsewhere.*

8) In places it reads like a legal brief by PG&E to push up the valuation of the electrical-distribution system in San Francisco.

Response: *This statement is false, as shown by reading the report and this response and by the criticism's failure to cite even a single example of this alleged problem. Use of non-citations such as "in places" highlights the lack of substance in this charge. We prepared a thorough objective analysis, instead of a brief for municipalization. ETAG would have failed its duty to*

the SFPUC and the people of San Francisco to have covered up the valuation issues or any other significant matters.

9) The report includes no bibliography, no index, no glossary of technical terms, and no relevant literature review.

Response: *This point is false in part and misleading in remainder. The relevant literature is reviewed throughout the report, as it applies to each section -- and Mr. Ventresca's comments here even address some of these reviews -- so Mr. Ventresca contradicts himself. A list of acronyms has been provided for inclusion. Technical terms and acronyms are explained as they are introduced and sometimes again subsequently. As explained to Mr. Ventresca at a TRC meeting, indexes and bibliographies are not required by the scope of work and are generally not used in reports such as these; hence, this part of the criticism is misleading.*

There are a number of major weaknesses and shortcomings in the ETAG study. For instance, the ETAG report:

10) -predicts, based on a series of misleading premises, that energy supply costs will be the same with or without municipalization (ES-5). A kilowatt generated by a hydroelectric dam will not cost as much as a kilowatt generated by a nuclear power plant.

Response: *First, this criticism once again hides behind the vague non-reference (as discussed above), by alleging "a series of misleading premises" without giving even a single example. Second and moreover, the essence of the criticism is wrong. The statement about hydro and nuclear power costs is not relevant to the contested conclusion -- i.e., that the cost for the energy component is the same in both options. The restructured electric industry, discussed in item 5 above, will feature a power exchange (PX) that will charge all buyers a single "market clearing price". This PX's energy will be provided by all suppliers that agree to the market clearing price. Each bidder to supply power will be paid the highest price required to obtain just enough supply to meet the demand. Thus, while the cost for energy from a hydro project or a nuclear plant may be different, in the deregulated market, the price the PX pays to all producers will be the same, and the power sold at any given time to various utilities will also be charged at a common price (that differs slightly from the purchase price). If a nuclear or hydro plant cannot bid a competitive price during a market period, then it will not run at that time.*

Moreover, under this arrangement, if CCSF owned a low-cost resource, it could provide exactly the same benefit to the people of SF by selling the output of that resource to the PX (with the difference flowing back to them as lower taxes, lower service rates, improved services or all of the above) as by using the resource as its own dedicated supply (in which case the benefit flows to them only as lower electric rates -- but the amount of their benefit is still the same: the difference between the market-clearing rate they would pay to the PX and the operating costs of the particular resource).

11) -attempts to claim cost and rate differentials between existing public power and investor owned utility systems are dominated by public power systems access to lower gross costs of capital (1-2; 1-29) which is false. Sixty percent of public power rate advantage is due to non-profit operations, local cost scrutiny, and commitment to public service.

Response: This criticism reflects a failure to understand what is apparent on the face of ETAG's report (and has been explained to Mr. Ventresca in TRC meetings and in written responses). First, the citations to pages in the ETAG report are to the summary and conclusion of chapter 1 -- and both statements cited refer to the specific analysis in section 1.B, which plainly shows and documents the fact that the rate differentials are dominated by the gross-cost-of-capital differences. (Table 1-3 on page 1-18 shows that the gross-cost-of-capital differences exceed the overall rate differentials, giving rise to the possibility that munis are otherwise less efficient than IOUs, when the costs are adjusted for this factor.) Our analyses are precise and specific to the six muni/IOU comparisons, two more than required in the scope of work. Hence, the "attempts to claim" language and the avoidance of a section 1.B citation misleads by ignoring the fact that ETAG's conclusions (which is all the criticism cites) are the direct result of rigorous quantitative analysis. Mr. Ventresca does not give a source for his figure -- but by its terms, it apparently comes directly or by David Penn's secondary citation from the Kwoka study discussed infra. *ETAG's report shows that the Kwoka study, and especially the conclusion quoted by Messrs. Penn and Ventresca, is invalid due to a key technical error which runs throughout it. For more detail, see our response to items 47 and 53 below.*

12) -alleges that absent cost of capital and income tax issues, public power is not significantly more or less efficient in delivering electric energy to ratepayers (1-3) which is false. This is contrary to most academic research in the field.

Response: This is simply a reprise of the immediately previous comment, in slightly different terms and with citation to a different page of the summary. Besides Kwoka's paper, we have reviewed the literature, as discussed in section 3.B of the report; we find that the academic research, taken as a whole, supports our assumptions, as we discuss in that section, and it does not support a claim of muni operating efficiency advantage. See also our responses to items 45-53 below.

13) -assumes AB1890 stranded costs or so-called competition transition charges (CTC) requirements will remove an advantage to public power (1-24), but neglects to mention that Representative Tom DeLay (R, Texas), the House Republican Whip, is pursuing legislation to ban any repayment to a utility for stranded costs. DeLay is working with environmental and consumer groups, including Citizen Action and Public Interest Research Group, to get the legislation passed (Wall Street Journal, December 17, 1996, p.A24).

Response: In a previous criticism, Mr. Ventresca faulted us for incorporating the effects of new law (AB1890) that has already been promulgated; he derided this practice as being speculative. Now he proposes that one should assume that the law will be changed, based on newspaper

accounts of legislation that may be -- but has not as yet been -- introduced. In any event, as explained in section 2.A, as well as in the section he cited, if the CTCs could not be recovered from muni customers that exits an IOU system, then the condemnation valuation for acquiring the distribution system will include stranded costs, and muni ratepayers will pay the equivalent amount in the purchase of the distribution system (i.e., through their muni electric rates). Thus, we have not neglected anything, for even if the DeLay legislation is passed and bars CTC charges to exiting ratepayers, it will not have any material effect on the muni rates and decision for SF.

Page Three

14) -overstates the valuation of the PG&E- infrastructure in San Francisco, including ETAG's high ($999 million) and low ($300 million) figures identified in their report, by solely relying on suspect 1981 PG&E (2-33) data (ETAG calls this 14 year old information (2-4) the "best publicly available cost data") that was generated in the middle of the Proposition K (November 1982) campaign to get a feasibility study. The data was challeged in a lawsuit filed by San Franciscans for Public Power at the time (Superior Court Case No. 799-076). This key, baseline, and foundational data, which comes directly from PG&E and was politically motivated, has never been independentedly verified.

Response: *There is no overstatement, as has previously been explained to Mr. Ventresca at a TRC meeting. The reason, as also explained to him and on which he does not report here, is that the ETAG report does not "solely rely" on the data from PG&E -- in fact, it relies on it very little. To develop a 2001 valuation, a starting valuation was needed, and the PG&E estimates were used for this purpose; however, as explained to Mr. Ventresca, over the 20-year period from 1981 to 2001, the growth and replacement components of the valuation accumulate to such a total, while the starting-point valuation is depreciated, that the starting-point value is completely overwhelmed by the growth and replacement components in the 2001 total -- for both the high and OCLD (not low) figures he cites here, as well as for the base-case number. (Our low figure was developed from the income analysis, which is not affected by this matter.) As Mr. Czahar explained to him in the TRC meeting, even a significant change in the 1981 valuation would make only an immaterial difference in the 2001 values.*

ETAG only used a small part of the 1981 PG&E data related to: 1) the identification of SF distribution assets; 2) their original cost; and 3) average age. PG&E did not produce an estimated net book value in its 1981 study, but did produce a Reproduction Cost New Less Depreciation value of $795-million, which we did not use for our estimates at all. ETAG compared the original cost estimate of identified SF distribution assets and determined that is was ***lower*** *than the PG&E's system average cost. ETAG compared the estimated age (or remaining useful life) of the property and determined that its* ***older*** *than PG&E's system average. The alternative to using these two values would have been to use the PG&E system average (see pages 2-32 and 2-33 of the Report). The impact of using of a* ***lower*** *than system average original cost value is* ***reduce*** *the net book value estimate. The impact of using an estimate of average age that is older than the system average age or remaining life is to* ***reduce***

the net book value. Thus, on two counts, use of the PG&E 1981 data in the manner it was used by ETAG errs, if at all, then in favor of municipalization -- as has been explained to Mr. Ventresca at a TRC meeting. Thus, further, his complaint his 180 degrees wrong, even though his error has previously been explained to him. It should be noted that net book value is not a value used by ETAG for its estimate of the range of possible condemnation values.

Original cost does not effect the Reproduction Cost estimate, since this estimate is based not on any PG&E data but on independent sources including the Sate Board of Equalization (see pages 2-35 through 2-41 of the Report) However, the age of the property does affect the estimate of Replacement Cost Less Depreciation (RCNLD). The impact on RCNLD valuations of applying ETAG's assumption that the SF distribution is older than PG&E's system wide distribution assets, and therefore is more depreciated, is to ***reduce*** *the RCNLD estimated value.*

Moreover, Mr. Ventresca's criticism does not suggest for use any other publicly available cost data on PG&E's SF system -- because, as our report states, there is none. Finally, the criticism misleads by alleging that the "key, baseline, and foundational data" (wrong: it's merely a starting point) was "politically motivated" and "challenged in court" -- while omitting the facts that the court challenge failed, The City voter guide relied on the data, the voters rejected the proposition, and a previous municipalization study at the University of California relied on the same data. The criticism also seems to obscure that there is no other source for such estimates, except PG&E, as explained to him at the TRC meeting. Also, the proposed $1,000,000 phase II study to verify or modify our original- and replacement-cost estimates would also require extensive access to PG&E records which we did not have,, as we explained to him.

15) -appears to claim it relied upon American Public Power Association (APPA) data and sources when it did not (1-2). ETAG selectively and consistently misused APPA materials to argue against public power.

Response: *False. The cited text explains clearly that we relied on the same data source as does APPA, and it does not make or appear to make the claim stated about reliance on APPA. Moreover, this point has also been explained to Mr. Ventresca, who advocated direct reliance on APPA's publication of this data. We explained that it would be bad practice for a number of reasons: 1) we got the data from the original source, just as APPA did, rather than relying on a secondary source (APPA here); 2) primary sources are always better than secondary sources for raw data; 3) APPA can be challenged in this matter an advocacy group, and the APPA article is especially so, while the data source is regular federal publications based on the legally required reports of munis and IOUs. The claim in the second sentence is wrong and reflects the fact that we used APPA materials, as appropriate, to show the benefits, costs and risks of both options, and not to brief the muni-partisan side only. Ultimately, the second sentence is untrue, because it alleges that ETAG's report argues against public power, which it simply does not; it presents an objective, balanced account, as required in this project, and it does not reach or even suggest a conclusion about the overall policy issue of municipalization. This point has also been explained more than once to Mr. Ventresca.*

16) -refuses to factor in the benefits of using low-cost, hydropower from Hetch Hetchy for the residential customers of San Francisco (3-10). In 1994 and 1995, megawatt hour (MWH) sales for San Francisco residential customers totalled 1.2 million (2-26). In 1994, megawatt hour (MWH) generation for the Hetch Hetchy power system totalled 1.6 million, according to the latest information available from APPA. In otherwords, power generated by the Hetch Hetchy system is greater than the power utilized by all residential users in San Francisco. The ETAG report recommends that none of the Hetch Hetchy power should be utilized by residential users in San Francisco.

Response: *This claim, "refuses to factor in", is false, as has been explained numerous times to Mr. Ventresca, and as verified by Hetch Hetchy staff. While the comparison of total Hetch Hetchy generation to the electricity use by residential customers in SF is eye-catching, it is not particularly illuminating. First, the residential load represents 28% of PG&E's 4,503 GWH sales to SF (pp.2-26 and 2-278 of our report). Second, as shown by the detailed discussion of this issue at page 5-17 of our report, 57% of the Hetch Hetchy load is committed by the Raker Act to serve The City's municipal loads (6/7ths of the 761 GWH shown in footnote 8 on p.5-17) and agricultural pimping loads of The Districts (271 GHW, same footnote; so [761 x 6/7 + 270] / 1,606 = 57%, where 1,606 GWH is the total Hetch Hetchy production, as reported in the same footnote) -- leaving at most only 683 GWH for SF retail service (= 43% of 1,606). Thus, under perfect circumstances, Hetch Hetchy generation alone could meet only 15% of SF's total retail load (= 683/4,503). Moreover, as explained at p. 5-17, even such a calculation as this greatly over-states the ability of Hetch Hetchy to serve SF retail loads, because only 0-200 MW of power would be available to serve the summer and fall peak load (900 MW) , when energy is most valuable (highest market-clearing price).*

Finally, the last sentence of this item is completely wrong, because ETAG makes no recommendation in this regard -- and, again, Mr. Ventresca does not provide a citation for this claim because there simply isn't one. (Page 3-10 does not, at all, say what this sentence claims we recommend.) In fact, page 3-10 and our explanations to Mr. Ventresca show that SF residential ratepayers already get the full benefit of the low-cost power generated by Hetch Hetchy in their roles as taxpayers and service users in SF. Moreover, as explained, were CCSF to attempt to sequester this benefit to residential electric rates in muni retail service (if it could in fact do so), then the form of the benefit would be changed but the amount of it could not be increased over the present arrangements.

17) -misstates a key mandate of the Raker Act (3-10). The Raker Act (1913) H.R. 7207 states unequivocally that "the said grantee (meaning the City and County of San Francisco) shall develop and use hydroelectric power for the use of its people."

Response: *There is no mis-statement. Although we discuss the Raker Act briefly at page 3-10, Mr. Ventresca has here not even stated what the alleged mis-statement is. Instead, he has quoted a part of the Raker Act, and not even provided his interpretation of it, nor any citation as to any statement by our report that he claims conflicts with the cited part. We, on the other hand, have chosen to rely upon the legal advice to the Board of Supervisors and departments, as provided*

by the City Attorney. In fact, our account of the Raker Act is consistent with the City's legal position on this matter over half a century, as we note at page 3-10.

18) -fails to state objectively public power advantages (3-14). There are significant benefits to public power that ETAG omits or downplays.

Response: This is false because the cited page and others contains exactly the objective account. To the extent this point relies implicitly on other criticisms in this list, it errs because each other point is also fully rebutted.

19) -ignores APPA criticisms that surfaced in the S. F. Bay Guardian on October 30, 1996. APPA, the experts in the field, has not been encouraged to submit formal written responses to ETAG's three drafts yet.

Response: The Bay Guardian *is, at best, a secondary source, and as discussed above, we avoid such reliance where reasonably possible. Further, the public hearings provide for adequate and fair comment and response. APPA may be viewed by some as the experts, but in this matter APPA is clearly a partisan, and thus should receive no more credibility than PG&E or the Edison Electric Institute (APPA's institutional opposite for these purposes). This view of APPA is explained in the report and has been explained in TRC meetings to Mr. Ventresca, as has ETAG's solicitation and use of materials from APPA. Staff has solicited comments from APPA on the most recent draft of the report, and we have supplied detailed responses to APPA's comments.*

Page Four

20) -relies on misleading, unverified PG&E data (throughout the report). The ETAG report is substantially based on questionable PG&E sources of information.

Response: This is false. To the extent it references the 1981 valuation estimates as a starting point, this item has already been answered above and is repetitious. As the report explains in various places, we relied on PG&E data that must be filed with the CPUC and FERC, data which is audited by those agencies, as well as by PG&E's own auditors. Once again, Mr. Ventresca is unable to give even one, two or three examples of an allegedly widespread problem or explain why a datum is "questionable". He merely slaps a derogatory label on it, as if that were a meaningful and integral act of review. We specified, critically considered and documented our reliance on PG&E data -- and it is fully appropriate as we did it, because the matter at hand involves the valuation, operation, characteristics, etc. of the PG&E system.

21) -claims falsely the Raker Act "does not require" Hetch Hetchy power to be sold to residents of San Francisco at retail rates (3-10). The text of the Raker Act and the clear legislative intent of the Congress requires that Hetch Hetchy power be sold to residents of San Francisco at retail rates.

Response: *See our response to item 17) above on the Raker Act. This item, too, merely repeats a previous one. As noted above, our position on the Raker Act follows over 50 years of The City's implementation of it and advice of the City Attorney.*

22) The report is riddled with erroneous assertions, incorrect assumptions, misrepresentations, pro-PG&E statements, and anti-public power comments, for example:

Response: *As shown in the detailed responses below, especially beginning with the next one, and throughout our report, this claim is completely false and the facts have previously been explained to Mr. Ventresca – who repeats his previous statements without even any recognition that they have been debunked, let alone any attempt to answer the thorough refutations we have made to his criticisms.*

23) Erroneous Assertions

Response: *The responses to specific items that follow show that Mr. Ventresca has consistently mis-characterized as "assertions" text from summary sections that sum up and draw appropriate conclusions from the detailed, rigorous, quantitative analyses in the body of each chapter and in the supporting workpapers. Except in one case (reference to page 1-13, item 26), he completely avoids going to the body of the analyses, and opts instead for answering well-documented, sound conclusions with "ain't so" blanket assertions and erroneous or no appeal to evidence.*

24) There is no true economic benefit for public power in regards to supply costs or non-profit operations (ES-5) according to ETAG. Utilizing lower cost sources of power and eliminating profits would create a benefit to San Francisco users.

Response: *The power-supply-cost item in this criticism merely repeats the error on this matter already answered above in response to item 10. The illusion involved in "eliminating profits" is explained at pages ES-7 and 4-21 and 4-22: on an expected-value basis, ratepayers are no better or worse off paying a regulated IOU equity return, as compared to self-insuring as muni ratepayer/owners. Nonetheless, we do show the nominal rate effects of these savings in the table cited at ES-5 (despite Mr. Ventresca's allegation to the contrary). This criticism also, once again, references a statement from a summary section while studiously ignoring the detailed analysis in the body of the report that addresses the same matter in more detail.*

25) "Data and sources on which we (ETAG) rely in these comparisons... are the same used by the APPA in its annual Public Power survey of muni and IOU rates ... and thus its data thus show the same results" (1-2). No they don't.

Response: *Yes, they do, and this item is repetitious of one answered above. Once again, Mr. Ventresca does not even attempt to give a significant example.*

26) "There are no clear differences in efficiency ... that allow one to conclude that munis are significantly either more or less efficient in managing operations that IOUs" (1-13). Research suggests that public power systems are more efficient than private power systems.

Response: *Again, the research is not even referenced in any way. And again, this point has already been made and completely answered above, as well as in the report and personally to Mr. Ventresca and in TRC meetings. Mr. Ventresca here quotes only part of a sentence in a way that distorts its meaning. The sentence from the text refers to using the results of the six muni/IOU pairs as a basis for these conclusions, and Mr. Ventresca does not even attempt to refute those results on their merits; he merely turns to sources with results he likes better, even though they have been refuted, or he simply mis-characterizes the results of other studies, as other responses here on those studies show.*

27) "it is impossible for municipalization to make other than small-to-modest differences in total costs and rates" (4-7). The opposite is true.

Response: *Once again, the criticism quotes a chapter summary section and ignores the detailed and rigorous body of the chapter being summarized. Once again, he quotes a partial sentence out of context in a way that distorts its meaning; in this one, the omitted material refers to the electric-industry restructuring changes, which obviate reliance on historic results at the total rates level. Once again, he answers extensive quantitative analysis with no specifics -- here just blithely asserting the contrary, with no showing of basis or justification even attempted.*

28) "The values used ... systematically favor municipalization" (4-7). Nonsense.

Response: *First, see the previous response. Second, our assumption that there would be no dis-economies of scale (despite the Kwoka results showing there would be) is an example. Other examples include the assumption of no loss in operating efficiency (despite the muni/IOU pair comparison results showing there may be such losses), as well as the assumption that de-averaging benefits can be assigned to the municipalization decision, even though de-averaging could be achieved on the PG&E system simply as a resultof the CPUC issuing an order adopting PG&E's area marginal-cost study as a rates basis. There are other examples, but no counter-examples, and Mr. Ventresca has not even attempted to produce one.*

Page Five

29) Incorrect Assumptions

Response: *The first four items below are all taken from the Executive Summary, and as is clear on their face, they represent the studied conclusions and summary of the detailed, quantitative, rigorous analysis in the body of the report -- which Mr. Ventresca does not even attempt to address. The final three items refer to the body of two chapters, repeating errors he previously made and whichhave been corrected when he raised them in TRC meetings. The responses to*

specific items that follow show that Mr. Ventresca has consistently mis-characterized these items as "assumptions". Except in one case (first reference to page 3-14, item 35), he completely avoids the logical requirement to present some evidence or other basis for his criticism, and opts instead for answering well-documented, sound conclusions with "ain't so" blanket assertions.

30) "The cost of energy supply ... will be the same for both the muni and (PG&E) ... options (ES-4). No they won't be.

Response: *First, see our response above to item 10 here. This matter is discussed also in section 3.A, which ES-4 summarizes in the referenced part. The "will be the same" conclusion is a product of extensive analysis and was arrived at in full consultation with Hetch Hetchy staff and consultants representing The City's efforts on a continuing basis in matters directly related to this conclusion. As stated in the text, the "will be the same" result reflects a market structure for bulk power supply that is an intended effect of the AB1890; this result is also accepted virtually universally by participants in the restructuring matters that have made such estimates (e.g., California Energy Commission staff and consultants). Against this consensus evidence we have Mr. Ventresca's unqualified assertion: "No they won't be."*

31) "Utility regulators disallow imprudent utility costs" (ES-7). Then why are consumers paying $15 billion to PG&E, through stranded costs, for Diablo Canyon?

Response: *They are not; as noted at the outset, the amount is perhaps $5.9-billion or so, and thus even though Mr. Ventresca has now changed his story about the amount by revising it upwards by 50%, the real amount is still much lower. At another level, the question appears to assume that any amount Mr. Ventresca asserts is imprudent should be disallowed; the amounts PG&E is recovering on Diablo Canyon, however right or wrong, reflect a settlement adopted by the CPUC with an evidentiary and procedural basis.*

32) "The real economic savings...are almost completely due to a single factor: the avoidance of state and federal income taxes by munis" (ES-9). This is only one of many factors that allow public power systems to have lower rates than private power systems.

Response: *This item in part repeats previous errors in Mr. Ventresca's criticism. However, to be very clear on this important point, we state the following on this matter. As a result of our thorough investigation of each cost factor, we find that the only systematic or significant expected-value difference in SF muni/IOU electric-distribution system economics following California's electric-industry restructuring is that IOUs pay state and federal income taxes, while public-power agencies do not. All other factors have been examined and found to be either definitively a zero expected difference (e.g., bulk power supply and transmission), attributable to policy decisions that can and should be made separately from the muni/IOU decision (e.g., area-cost de-averaging and CTC avoidance), or apparent rate differentials that do not reflect real economic differences but instead reflect real economic equivalence (e.g., muni distribution-system acquisition premia and IOU equity-return premia). Economies of scope,*

scale and operating efficiency could disfavor the muni option (especially for scope) in other settings, but we have assumed (giving the benefit to the muni option) that they will not do so for SF. None of the other literature cited by Mr. Ventresca has even attempted the kind of analysis we have applied here to the municipalization decision, and most of it addresses only results for long-existing munis and IOUs. Further, for the purposes for which Mr. Ventresca cites the other material to buttress his claims in this area, it is wrong, contrary to his claims in its showings or simply inapplicable. (See especially our responses below to items 45-53.) Mr. Ventresca's claim of "many other factors" is simply false. (See especially our responses below to items 54-71.)

33) ETAG completed a "definitive"feasibility study (ES-9). No they did not.

Response: *As shown especially in the immediately previous answer, as well as throughout the report and these responses, we have indeed done so. This work has gone further and more definitively into the basic economics of the municipalization decision than any other source that has been cited, and it has directly and rigorously applied it to the SF situation. We think that is definitive. The report points out that its estimates of original and replacement costs, while the best that can be done without a million dollars of field work, are not fully definitive on these numbers; however, it also points out (and we want to emphasize here) that, to decide the basic policy issue of whether to go forward with municipalization, it is fully definitive and adequate because the exact amount of the acquisition premium is shown to not affect the basic muni/IOU economics if one assumes (the only reasonable assumption) that a condemnation proceeding is expected to yield the true value. As the report points out, then, the more detailed valuation study is required only if the decision, at least provisionally, is to proceed with municipalization.*

34) "The 1981 estimate of the original cost of the San Francisco distribution system is a reasonable starting point for our (ETAG's) analysis of NBV (Net Book Value)" (2-23). No its not.

Response: *In our response above to item 14 and in TRC meetings, this item has previously been raised and answered to show that it is incorrect. The noteworthy thing about Mr. Ventresca's revisiting of it here is that he again fails to do the obvious and necessary: state what are feasible other options and indicate which is better and why. As we have noted, there really are no good other options. Moreover, because the 1981 starting-point data do not greatly affect the 2001 valuation (as discussed above), our use of this data is wholly reasonable.*

35) "The public ownership efficiency conclusion is suspect" (3-14). No it's not. Superior public ownership efficiency is documented in the academic literature.

Response: *This point has been raised above in item 11 and answered, including a citation to our detailed review of the literature in response below to items 45-53. Actually, the conclusion is more than suspect in the Kwoka study. As noted in response to items 11 and 47 and section 3.B of the report, the error in the Kwoka study is of such a nature that it appears to directly and incorrectly lead to a public-ownership cost margin; even if that is not the case, the error in the*

Kwoka study pervades its entirely and renders all of its conclusions null and void. The rest of the literature, which we reviewed in part in the study and in previous responses here and at TRC meetings to Mr. Ventresca (and detailed in items 45-53 below), simply does not support claims of muni operating advantage, taken as a whole. If it shows any advantage, it is on the IOU side, but we did not use that conclusion, instead assuming no difference. Our own direct data from the six muni/IOU direct comparisons tends, if anything, to support an IOU advantage, although we did not reach for such a conclusion, even adding our results to the literature. This claim, like the others, is simply another assertion that does not even purport to present specific evidence.

36) Public power arguments "add little (and) nothing substantial" to the, ETAG analysis (3-14). The benefits of public power are not understood by ETAG.

Response: *This is another example of misrepresentation by partial quoting out of context. The mis-quoted text does not refer to "public power arguments", which we thoroughly reviewed and on which we fully relied where appropriate (e.g., income-tax exemption; and the reasons to ignore the acquisition premium, a "public power argument" we developed for the first time in the report). As it states, it refers to the some claims and sources raised by partisans in the process. Clearly, we understand the benefits of public power, having pioneered perhaps the most salient point (re: the acquisition premium).*

Misrepresentations

37) "Since 1975, only one actual electric municipalization attempt (Hayfork/Trinity) has been made in the PG&E service area" (1-3). There was one in Folsom in 1989. This was the largest condemnation case in California in the last 17 years. It was between SMUD and PG&E. The head of ETAG worked for PG&E.

Response: *The point of the review summarized at page 1-3 and detailed in section 1.C was to review the experience of cities and other local governments in forming new public-power districts for electric-utility retail service. The report is correct in stating that the Hayfork/Trinity case provides the only example of such experience in the last 20 years. The Folsom case was an annexation by SMUD of a PG&E service area, and thus it was not within the scope of work because reviewing it would not provide insight into the full range of issues, as does a review of a new municipalization. In fact, as discussed with him at TRC meetings, the Folsom case and all other condemnations, annexations and voluntary electric-system transactions in the last 17 years in California for which data are available were reviewed -- an effort beyond the scope of work -- and are summarized by line in the workpapers volume, section 2.B. Hence, contrary to the suggestion that we missed a significant item, we caught it and all other even slightly relevant cases and gave each its due weight in our assessments. In addition, Mr. Knecht's role as an expert witness in that case provided us and The City with valuable insight into PG&E's views on these matters, as well as specifically into the Folsom case. If the result of the Folsom case were followed for SF, the valuation would lie in the $795-million to $1-billion range or higher -- not the $795-million or less view adopted by us.*

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38) The report covers-up the context where the 1981 PG&E data came from (2-23). This suspect data should not have been used.

Response: At the cited page, the report does not even address the matter of this criticism -- an example of a number of similar problems in these criticisms. But we do not use such problems to avoid the substantive point -- so, assuming he meant page 2-33, the "covers-up" claim can be addressed. The source of our first-year data starting point -- PG&E -- is, in fact, disclosed clearly all over the page. This is an example of an endemic problem with Mr. Ventresca's participation: any time we did not adopt his views, he railed at such non-adoption as being a "cover up", "suspect" or worse, when in fact it would have been error to have adopted his biases, etc. Finally here, as previously noted, Mr. Ventresca has not even suggested an alternative starting point or attempted to show that some other initial data is superior for the purpose at hand; and he continues to run away from the fact (we explained to him in detail and at length) that reasonable levels of error in the starting values are thoroughly minimized by our method to the point of insignificance in our final valuations.

39) Pro-PG&E Statements

Response: As shown by the responses to these two items, below, they aren't even "pro-PG&E statements", but matters of fact to which Mr. Ventresca apparently objects.

40) "If there were ... (a lose in value of the PG&E Hunters Point and Potrero power plants after municipalization), then the City would owe PG&E compensation for that loss in value" (1-22). One would think the City would argue against this.

Response: Case law is clear on the matter, as explained in section 2.A of the report and explained to Mr. Ventresca more than once in a TRC meeting: PG&E would be able to recover such losses in value caused to these assets.

41) "CCSF (the City and County of San Francisco) may need the two power plants to provide for the reliability for an SF muni utility" (1-22). The City should never operate major fossil fuel burning power plants in the City limits.

Response: Even if we agreed with this viewpoint, we are truly at a loss to understand how the statement qualifies as a "pro-PG&E statement". Moreover, because it was discussed with him at TRC meetings, Mr. Ventresca should know that there is no alternative to using these plants if SF is to have reliable electric service. Perhaps almost daily rolling blackouts would be acceptable to him, but it would not pass muster with the people of SF and would be terrible public policy. Again, Mr. Ventresca has not suggested an alternative, because again there is no sound alternative within the horizon. In any event, whether they are owned by CCSF, PG&E or someone else, these two plants are needed for the foreseeable future to provide reliability to the people and businesses and other electric users of SF.

42) Anti-Public Power Comments

Response: *As was the case above for the allegedly "pro-PG&E statements", and as shown by the responses to these two items, below, they aren't even "anti-public power comments", but matters of fact to which Mr. Ventresca apparently objects.*

43) "Stranded costs for PG&E... (because of) AB1890 ... tend to remove a traditional advantage of municipalization" (1-24). The stranded costs requirements may be changed by federal legislation.

Response: *This is a repeat of a previous item and even if its speculative hope is realized, it in no way qualifies as an "anti-public power" comment. First, he seems to want us to adopt his speculation as a fait accompli, even though it is fully contrary to recently promulgated law. As the law stands now, it removes a traditional advantage of municipalization.*

44) "Munis pay as much or more to distant investors as do IOU" (3-14). This is not the case. The retention of capital in the local economy is one of the major advantages of public power. When private power utilities finance debt they pay high interest rates to investors outside the local area. When public power utilities finance debt they pay low interest rates to investors outside the area. The result is that public power means less capital flight from the local economy. Private power monopolies generate high guaranteed profits and a part of this is paid out in dividends to distant stockholders. Public power consumer-owned systems operate as non-pofits which pay no dividends to distant stockholders. Again, the result is that public power means more capital is retained in the local economy to spur economic development.

Response: *This criticism is all wrong, even on its own generic terms, and it is especially wrong on the matter of SF municipalization. The claim about relative muni and IOU debt rates is wrong, at least for condemnation acquisition, because (as discussed in the report and explained various times in TRC meetings to Mr. Ventresca), tax-exempt bonds cannot be used for such takeovers. Thus, the rate for both PG&E and CCSF is 7.5% for debt financing here. On the equity side, the combination of IOU preferred equity with dividends below debt rates (due to income-taxability reasons) and the roughly 65% common-equity payout ratios versus the 11.6% earnings rate (current and consistent with the 7.5% debt costs), means that the effective equity cash payout rate will be only slightly above the 7.5% muni interest payout to distant investors for the debt financing used to replace PG&E stock. In sum, then, for each dollar financed, the IOU payout (half debt- and half equity-based) to distant investors is only slightly above that for munis (100% debt-based). But the story does not end there, for the two options do not involve the same levels of dollar financing. The existing IOU financing is based on the original-cost-less-depreciation value of $315-million, while muni financing would be based on the condemnation valuation, with a base case of $795-million. Thus, with a weighted cash payout rate of about 7.52% for IOUs and 7.5% for munis, and with the ratio of amounts financed exceeding 2.5 (=795/315), the IOU payout to distant investors would be expected to be 40% of that for the muni. Even if the valuation were set at $505-million (our low-cost value) and if*

somehow refinancing could be done using tax-exempt bonds at 6% (which we believe would fail IRS rules), the IOU payout rate to distant investors would still be less than 78% of that for the muni. In sum, the closer one looks, the more this partisan shibboleth is seen to be completely wrong or backwards. The foregoing analysis also leaves aside the point that IOU stockholders (including many individual investors, who tend to gravitate to local firms in their purchases) generally live more in the area than do muni bondholders (which are more institutional and thus more likely to be based in New York). Thus, if avoiding payouts to distant investors is important (and we think not), then municipalization is the wrong way to go.

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45) Misuse of APPA Materials

Response: *As shown in the responses to the items under this heading, "Misuse" here consists of not agreeing with APPA conclusions. There has been absolutely no misuse by us of APPA materials, but as pointed out in the report and explained to Mr. Ventresca in a TRC meeting, we in fact relied extensively on APPA materials and did not rely on the partisan materials from the other side (EEI).*

46) The APPA is referred to on 14 pages (ES-1; ES-6; 1-2; 1-10; 1-21; 1-22; 2-21; 2-23; 3-12; 3-14; 3-15; 4-21; 4-26; 5-10). ETAG selectively misused APPA materials to argue against public power. ETAG did not obtain written responses from the APPA concerning their three drafts. ETAG saw the experts in public power, the APPA, as biased and did not fairly utilize APPA research.

Response: *The first sentence merely makes the point we stated above: that we used APPA material extensively, EEI material was not used at all. Once again, the "selectively misused" claim is a charge without even any attempt at a single citation or explanation as to exactly what was mis-used, how it was mis-used, what the correct use would have been, why, etc. If it refers to the items below, then it is wrong, anyway, for each of those items is shown in its response to be completely wrong. The third sentence merely repeats a previous complaint that ETAG had an obligation to seek (uniquely) APPA's review (as if very extensive and intensive staff, other consultant and TRC review, public hearings, etc. was not enough). In any event, because staff has sought and received APPA review (to which we respond separately), this point is moot. The final sentence seems to suggest that APPA is not biased -- a remarkable assertion, as shown by simply reading APPA's advocacy documents provided by Mr. Ventresca and as documented in the report and our responses to Mr. Ventresca and to APPA's review.*

47) ETAG unfairly declared that the "Pricing in the Electric Power Industry" (December 1993) paper by John Kwoka is based on a "fundamental error" because the profits variable excludes total profits that go into retained earnings (3-13). The findings and conclusions of this paper are valid and consistent with other academic research.

Response: The "valid" claim has already been answered in response to item 11 above, as well as in chapter 3 of the report. Regardless of the consistency of this paper's results with anything else, they are not valid in their own right (even though, as we note in the report, some of the conclusions may in fact be proven by other means to be true) because the methodology is erroneous in a major way on its face and appears to directly introduce bias into the primary results on which Mr. Ventresca relies. In fact, it appears that the primary result -- the claimed efficiency of publicly owned utilities -- may be greatly or completely explained by this error, or the magnitude of the error may even exceed the purported efficiency effect, in which case the efficiency advantage would lie on the IOU side. However, while the nature and direction of changes in the results as a consequence of correcting the error may be apparent, their magnitude can be determined only by rerunning the statistical analysis with the correct data -- i.e., by redoing the entire Kwoka study correctly.

The allegations about what the rest of the literature shows have also been answered above, and also in greater detail in the immediately following points, which specifically address the literature to which Mr. Ventresca refers. Hence, the claim of consistency with (some) other research would be irrelevant, even if true, because that literature does not show what Mr. Ventresca claims it shows. (For example, the next item addresses a 1991 paper by Hausman and Neufeld, with Mr. Ventresca ignoring completely the key point that the paper, by design, addresses the performance of utilities not subject to regulation, and is thus inapplicable to PG&E and other modern electric systems that are regulated.)

Finally, the "unfair" criticism fails for two other reasons. First, the criticism merely labels the ETAG's diagnosis as "unfair" without even alleging that the error we diagnosed is not in fact an error, let alone trying to prove it was not an error. Until Mr. Ventresca proves that there is no error, the claim of unfairness simply cannot be true. That is, simple logic requires that our criticism of the Kwoka paper must be shown to be wrong as a pre-condition to showing that it is unfair. Second, Mr. Ventresca does not acknowledge a fact we disclosed to him in a TRC meeting: before publishing our studied conclusion that there was an error, we called Mr. Kwoka and asked for an explanation or defense on this matter, and he was unable to provide any; he said he would get back to us after checking it out if there was some saving explanation, but he has not done so.

48) ETAG claimed that the "Property Rights Versus Public Spirit" (August 1991) paper by William Hausman and John Neufeld was "irrelevant" because century old data was used (3-15). The paper included recent work on the efficiency effects of ownership and cited four studies (Cote (1989); Pescatrice and Trapani (1980); Neuberg (1977); and Meyer (1975)) that found evidence of greater efficiency in publicly-owned firms.

Response: Once again, Mr. Ventresca quotes only part of what we said on an item. We noted that the Hausman and Neufeld data is all more than 98 years old -- and that, by itself, would raise serious questions about the study for reliance here, if not disqualify it altogether. But, as noted in the immediately previous response, Mr. Ventresca then ignores (by partial quoting out of context) the really important problem: the stated intent of the Hausman and Neufeld study was to examine the behavior of unregulated private monopolies, as compared to publicly owned

monopolies in the same sector -- and thus it is expressly not applicable to this study and it does not show what APPA claims it shows in citing it. So, use of "irrelevant" was right on the mark.

Further, when Mr. Ventresca says the paper "included" recent work, he does not mean that it had any analysis of data from the 20th Century, for it does not; instead, he means that it includes a two-thirds-page brief review of selected recent work. From Mr. Ventresca's account, it sounds as if only four studies were cited, and all of them support the claim of greater public-sector efficiency; this notion is absolutely false. The section cites two studies that show that private utilities are more efficient, plus three others that explain why this is so, and six that show there is no difference. Thus, instead of Mr. Ventresca's 4-0 report, the count is 4-5 (i.e. ,in favor of IOUs), with 6 ties. However, as discussed in answer to the second following item (again on a Hausman and Neufeld paper), some of the studies cited on this page are not applicable here because they do not involve electric distribution systems; when the count is corrected to cover those that include electric distribution operations, then it is 3 for IOUs, 2 for munis and 2 ties.

Mr. Ventresca's incomplete and misleading 4-0 account would be very unsound professional and public-policy practice -- especially considering that, to reach his count, one must ignore the two sentences immediately preceding and following the one with the four studies he cites. On the other hand, our studied conclusion of no supportable difference between muni and IOU efficiency and our use of that conclusion is consistent not only with the sources he cites (when they are read in their entirety), but also with the rest of the literature, as the discussions here and in chapter 3 show.

49) While misrepresenting the two studies referred to above, ETAG ignored entirely the following studies that were brought to their attention on December 16, 1996 at the Technical Review Committee:

Response: *As discussed in the immediately preceding responses, it is Mr. Ventresca who misrepresents those studies and other matters. In addition, he misrepresents this matter, too, by ignoring footnote 18 on page 3-14, which explains that Mr. Ventresca and others provided various APPA and other materials to us during the process. As stated there, we reviewed them thoroughly but did not have room to fit them into an already long report -- especially given their limited relevance, in view of the support of our usage by the broad range of the literature, as discussed in at the end of the immediately previous point.*

The following background sheds light on what is actually going on here. Based on our professional familiarity with the electric-utility industry and economic literature, our study used an assumption of no muni/IOU efficiency difference as being either most likely or reasonably favorable to the muni option. After reviewing the first draft, Mr. Ventresca complained that we had not relied on the APPA document, "Straight Answers to False Charges Against Public Power". Another TRC member, Eugene Coyle, complained that we did not rely on the Kwoka paper (which states it is the product of research sponsored by APPA). These two papers were held out as being definitive on the issue. We then reviewed them in our next draft, showing the fundamental error in the Kwoka paper and the argumentative character of the APPA paper as reasons they should not be relied on by anyone. After the allegedly definitive items were shown to be invalid, Mr. Ventresca accelerated a campaign to: 1) attack us and our study for failing to

agree with him; and 2) replace these one-sided accounts with other claims of superior muni efficiency. As a short-cut to this claim, Mr. Ventresca added his own interpretations (and those of APPA's Mr. Penn see the response to the fourth following item on his paper, from which Mr. Ventresca copied extensively) of the many materials he and APPA have assembled. Our continuing review found that the literature did not show what he claimed it does. Now that he has pressed and expanded the point by putting new and previously refuted claims on paper, even after having had explained to him his errors along the way, we have no choice but to explain in detail, as we do here, why each and every point is so wrong.

50) -John Donahue of Harvard's Kennedy School of Government concludes in a recent book (The Privatization Decision) that "no study even hints at superior private efficiency" for IOUs.

Response: *As shown by the Hausman and Neufeld paper discussed above (among others), which Mr. Ventresca himself cited as an authority in this area, this claim is simply false. Five studies cited by those two authors, as well as others they do not cite, do much more than hint at it -- they make the claim explicit. As we noted above, the literature as a whole generally bears out our view that there is no basis to conclude that either munis or regulated IOUs are more efficient. And that really gets to the point in rebutting this item, for the way in which this criticism is put seems to suggest that we claimed superior IOU efficiency. It simply isn't so. We assumed the same levels of operating efficiency for a CCSF muni and a regulated PG&E in SF service. That in no way conflicts with the quote from Donahue.*

51) -William Hausman and John Neufeld in their paper "Public versus Private: A Summary of the Economic Literature on the Comparative Performance of U.S. Electric Utilities (October 1990) examined studies over a 20 year period and found either no significant efficiency differences or a greater efficiency for public power systems.

Response: *This is another flat-out mis-representation of an item from the literature -- especially as applied to the context of this study. Below is a list of the papers cited in this Hausman and Neufeld paper as either "The Recent Empirical Literature" or "Modern Analysis", not including those papers that do not address the question of IOU/muni efficiency. In particular, we highlight the conclusions of each paper as applied to electric distribution systems -- the issue here. On that basis, four of the studies support higher IOU efficiency, one supports higher muni efficiency, three show no difference, and five are not probative because they address electric generation, but not distribution. (Note in this regard: Hausman and Neufeld argued in their paper with some of the conclusions of the other papers, and sought to recast them, contrary to what the authors of those papers concluded about their own work. They did so while alleging bias by some other authors, which is remarkable, because their work was expressly sponsored by APPA. Our account presents what the other authors themselves concluded, where that differs from the Hausman/Neufeld account, and we do not inject our own attempts to alter the conclusions, as they did.) We present them in the order Hausman and Neufeld did.*

- *Boardman & Vining, April 1989,* Journal of Law and Economics*: "Ownership and Performance in Competitive Environments: A Comparison of the Performance of*

Private, Mixed and State-Owned Enterprises" -- This survey, widely cited by everyone except Ventresca and APPA, shows many more studies concluded that private electric service is more efficient than public than the number that concluded to the contrary or found no difference. ***Results favor IOUs.***

- *Peltzman, 1971* Journal of Law and Economics, *"Pricing in Public and Private Enterprises: Electric Utilities in the United States" -- Also widely cited, as Hausman and Neufeld admit while challenging its conclusions, private utilities are more efficient because publicly owned utilities mis-price service due to political pressure.* ***Results favor IOUs.***
- *DeAlessi, 1974* Public Choice, *"An Economic Analysis of Government Ownership and Regulation: Theory and the Evidence from the Electric Power Industry" -- This survey concludes that private utilities are more efficient.* ***Results favor IOUs.***
- *DeAlessi, 1975* Economic Inquiry, *"Some Effects of Ownership on the Wholesale Prices of Electric Power" -- Although Hausman and Neufeld conclude that this article shows no difference, instead of an IOU advantage, the argument is mooted by the fact that this item addresses bulk-power supply, not distribution.* ***Results do not address distribution.***
- *Moore, April 1970* Southern Economic Journal, *"The Effectiveness of Regulation of Electric Utility Prices" -- In the words of Hausman and Neufeld, this statistical analysis which addressed residential electric rates, "found a significant difference in favor of privately owned firms."* ***Results favor IOUs.***
- *Yunker, Fall 1975* Journal of Economics and Business, *"Economic Performance of Public and Private Enterprises: The Case of U.S. Electric Utilities" -- As Hausman and Neufeld state, "the basic conclusion from this investigation would have to be that no significant ownership effects were found."* ***Results favor neither -- i.e., favor ETAG's usage.***
- *Meyer, November 1975* Review of Economics and Statistics, *"Publicly Owned versus Privately Owned Utilities: A Policy Choice" -- Again, in the words of Neufeld and Hausman, "no significant ownership differences for transmission and distribution costs." This is an item mis-classified by Ventresca in his 4-0 count, because he did not look at the results specific to distribution.* ***Results favor neither -- i.e., favor ETAG's usage.***
- *Neuberg, Spring 1977* Bell Journal of Economics, *"Two Issues in the Municipal Ownership of Electric Power Distribution Systems" -- This paper reports a 6% to 26% advantage for munis. ETAG's 6.4% base-case results in this study lie within this range; in fact, when the 55% of production and transmission costs are set aside, as Neuberg did, ETAG's base-case margin is 14.2%, which lies squarely in the mid-range of these results.* ***Results favor munis -- and they very much support ETAG's results.***
- *Pescatrice and Trapani, April 1980* Journal of Public Economics, *"The Performance and Objectives of Public and Private Utilities Operating in the United States" -- As Hausman and Neufeld state, "Data were gathered for the generation of electricity only."* ***Results do not address distribution.***
- *DiLorenzo and Robinson, Summer 1982* Quarterly Review of Economics and Business, *"Managerial Objectives Subject to Political Market Constraints: Electric Utilities in the U.S." -- This study considers generation costs only, and as Hausman and Neufeld state, "the dummy variable representing ownership was not significantly different from zero" --*

meaning that statistically, this study showed no advantage to either side. ***Results do not address distribution.***

- *Fare, Grosskopf and Logan, February 1985* Journal of Public Economics, *"The Relative Performance of Publicly-Owned and Privately-Owned Electric Utilities" -- This study also considers generation only, and finds, per Hausman and Neufeld, "No significant difference in overall efficiency."* ***Results do not address distribution.***
- *Atkinson and Halvorsen, April 1986* Journal of Public Economics, *"The Relative Efficiency of Public and Private Firms in a Regulated Environment: The Case of U.S. Electric Utilities" -- This study also addresses generation only and finds, per Hausman and Neufeld, "No significant differences in efficiency."* ***Results do not address distribution.***
- *Hollas and Stansell, October 1988* Southern Economic Journal, *An Examination of the Net Effect of Ownership Form on Price Efficiency: Proprietary, Cooperative and Municipal Electric Utilities" -- Hausman and Neufeld begin their review of this item with: "This study used the most recent data and modern methodology to conclude that privately owned utilities were more efficient than were municipally owned utilities." It concludes, "Although flawed, the study by Hollas and Stansell was the only one to use data less than twenty years old." Unfortunately, it did not address distribution.* ***Results do not address distribution.***

Part of the problem here is that Mr. Ventresca just copied the characterization of this study from APPA and did not investigate these matters at all himself -- or he would have found two things. One is that the APPA characterizations wrong, and the other is that the results are different in some cases for distribution systems (the relevant matter here) than for generation.

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52) -Lon Peters in his paper prepared for the Western Conference Rutgers Advanced Workshop (July 1991) determined that "almost all studies of costs and efficiency found either no significant differences between ownership types or an advantage of some type in favor of publicly owned (nonprofit municipal) firms."

Response: *Whatever he may or may not have "determined", according to this account that Mr. Ventresca borrowed from APPA, this item is also wrong and misleading. First, the list above from the Hausman and Neufeld paper (which was produced for APPA and thus does not favor the IOU option by nature) shows quite to the contrary on Mr. Peters's claim. Second, even taking this account of the Peters paper at face value, Mr. Ventresca is misleading the Commission by suggesting that somehow Peters's paper conflicts with ETAG's treatment. As anyone who reads our report knows, it just isn't so: we assumed that muni operations are just as efficient as IOU operations for all the services that CCSF would take over.*

53) -David Penn in his paper "Public Power's Vital Procompeiitive Role in the U. S. Electricity Industry's Future" (December 1995) found that comprehensive empirical studies show that 60 percent or more of the public power rate advantage cannot be explained by the sum of the effects

of variables like public power's tax free status, tax-exempt financing, and access to federal preference power. Sixty percent of the public power rate advantage remains due to the inherent nature of public power, principally its non-profit operations, local cost scrutiny, and public service purpose.

Response: As noted above, Mr. Ventresca copied almost all his accounts of the other studies from this paper -- so he should be familiar enough with it to know that this issue was not the central point of the Penn paper. Instead, Mr. Penn's paper completely relied for the conclusions that Mr. Ventresca here quotes on the Kwoka paper (and two Kwoka derivatives of it that suffer from exactly the same basic and pervasive error -- as we explain in answering APPA's comments that cite those two papers) and, to a lesser extent, on the other papers discussed above. Since Mr. Ventresca's account of those papers and their relevance here has been shown in each case to be wrong, the fact that he now adds a summary of Penn summarizing them is also completely irrelevant and misleading and adds nothing.

54) Advantages to Public Power

Response: Our study provides a definitive assessment of what the prospective advantages of public power are for The City and the people of SF. It shows they are systematic and modest (6%) -- and mainly due to avoiding state and federal income taxes.

55) There are significant advantages to municipalization that ETAG ignores or downplays.

Response: Much of this is another list that appears to be cribbed by Mr. Ventresca from APPA documents, just as was the literature review above. As discussed below in response to each item, it simply is not true that we ignored or downplayed any of these items that is relevant and valid (as many are not), and that fact is indicated by our report and as discussed in TRC meetings.

Public power systems:

56) -allow local democratic control, local decision-making, and local ownership by all consumers.

Response: We recognized this point in many places, and chapter 1 even addressed the need to martial public support for municipalization, if it is elected, because PG&E will oppose vigorously and with great resources. As another example, we outlined the public processes in chapter 5 on the road to municipalization, if it is elected.

57) -are not-for-profit and do not pay dividends to distant stockholders.

Response: We recognized this throughout -- as discussed above, where we showed that a competent assessment of the matter of payments to distant investors favors the IOU option. This point was answered a number of times very clearly for Mr. Ventresca in a TRC meeting. Moreover, the not-for-profit aspect is at the heart of the reduced rates we show as a result of the

gross-cost-of-capital difference (no equity financing and no income tax payments) throughout the Executive Summary and chapters 1, 2, 4 and 5. It leads to a 5.6% tax-avoidance benefit, as well as a 2% equity-premium (versus muni bond interest) rate differential. Thus, this criticism suggests a failure to understand the basic issues involved here, or a really gross mis-representation of them.

58) -have lower administrative costs, including lower management salaries.

Response: *They have lower management salaries, as we reflected in our study, and they also have a smaller base over which to spread them -- so it generally is not true that they have lower administrative costs. This point applies to senior executive salaries, as well as other salaries for PG&E personnel that exceed CCSF's salary cap. As discussed in section 3.B of the report and in connection with items 45-53 above, there is no evidence for the bald assertion concerning administrative costs -- and it certainly does not flow from one-to-one salary comparisons, given the scale differences. Also, as we have noted, including at TRC meetings, senior executive salaries are immaterial, constituting less than one-tenth of one percent (0.1%) of the total electric cost of service in SF -- so this is a symbolic point only and thus a waste of time.*

59) -operate in the sunshine and have rates that are locally set by citizens controlled boards.

Response: *This is a repeat of item 56 here. Perhaps the repetitiousness was overlooked because each item in this list since the first one appears to have been copied directly from an APPA document ("Straight Answers ..." at p. 5 or Penn's "Public Power's Vital, Procompetitive Role ..." at p. 14). But, upon serious consideration, one recognizes the relevance on this matter of the point made in the Peltzman article cited by Hausman and Neufeld: publicly owned utilities often mis-price services due to political pressure, and that diminishes human well-being and contravenes the public interest.*

60) -utilize tax-exempt financing.

Response: *To the contrary, we mentioned this point throughout -- but we also added research and analysis. As we pointed out in section 2.F and discussed in TRC meetings, using tax-exempt funds for a CCSF take-over is not allowed under federal law (a 1987 bill sponsored by Congressman Rostenkowski -- as even page 8 of "Straight Answers to False Charges ... " reveals). Moreover, it is unlikely that tax-exempt bonds could be sold under a scheme to refinance the taxable bonds shortly after take-over, and there is serious question whether state and local tax-exempt financing rules would give CCSF any access to such bonds.*

61) -use low-cost hydroelectric power marketed by federal and state agencies.

Response: *We also discussed this point in detail in chapter 3, showing that however much it may benefit existing munis, it is immaterial to CCSF's prospects now. This point was emphasized in TRC discussions, as well as in the report. See also the answer to item 16 above.*

62) -promote energy conservation, safety, and sustainable environmental policies.

Response: *In chapter 1 and its workpapers and in chapter 5, we addressed the fact that the California IOUs, including PG&E, have among the best records in this regard in the nation -- and that, if anything, California munis have done less than the state's IOUs. But we emphasized in a TRC discussion that this matter is controlled by local policy, and SF will have the full range of options -- while of course (as noted in chapter 5) incurring the associated costs.*

63) -obtain equal or greater reliability and equal or greater efficiency than private power utilities.

Response: *This item, too, repeats a point stated and answered at length above, especially as concerns efficiency in items 45-53. Again, the way it is phrased misleads the reader into thinking that we assumed that munis (and a CCSF muni in particular) are characterized by lower reliability or efficiency than IOUs -- and that is simply untrue.*

64) -incorporate innovative techniques and technology into meeting energy needs more easily than private utilities.

Response: *There is absolutely no evidence for this claim, and much evidence to the contrary, especially as discussed in answer to item 62 above. Some of the recent empirical literature cited by the 1990 Hausman and Neufeld paper for APPA discusses this point. This claim is also directly inconsistent with the first item in this list, for more public process inherently slows down such incorporation, while the incentive structure of unregulated competitive sectors do much better on this matter and regulated utilities fall in the middle ground. Even the "Straight Answers ... " document refutes this generality, at page 12: "Public power utilities use the same technology as investor-owned utilities to deliver electric service to customers."*

65) -are more accountable-- every resident is an owner with a direct say in policies-- because customers have easier access to public policy decision-makers and management decision-makers.

Response: *We emphasized all aspects of the ratepayer/taxpayer/owner role of SF residents in detail throughout the report, especially in the Executive Summary and chapters 2 and 4. In fact, we analyzed fully its pluses and minuses, and that is why our economic analysis shows a 6% muni advantage, instead of the 3% advantage in the rates-only analysis. On the other side, note again the caveat on mis-pricing due to political pressure raised in the Peltzman article cited by Hausman and Neufeld, but overlooked by Mr. Ventresca. In short, the basic points were emphasized in TRC discussions with Mr. Ventresca, as well as being addressed at length by the report.*

66) -keep a greater portion of revenues in the local community.

Response: *This is a repetition of a point that has been answered at length (e.g., response above to item 44), showing that it is completely false, and that a takeover will drain more returns to distant investors than does PG&E. If we erred at all on it, we did so by failing to make the contrary point in the report. However, we did emphasize it at length to Mr. Ventresca in TRC meetings -- and, as in every other case, he has not even recognized the refutation here, let alone even attempting to shoulder his burden to provide an answer based on evidence and logic (instead of just assertion).*

67) -encourage a broader tax base, job creation, and economic development through lower rates; and

Response: *Once again, this claim is false in its implication and does not analytically address the local situation. We addressed these issues correctly in section 4.B, where we showed that all these factors are likely to be negatively affected by a move of PG&E corporate offices and the resulting loss of many SF jobs than they are to be positively impacted by small electric rate cuts. This point, too, was discussed in TRC meetings, as well as in the text -- but, again, Mr. Ventresca provides no substantive answer, just generalities.*

68) -provide transfers of revenues to local government general funds for other city services.

Response: *Wrong by 180 degrees, again. We addressed this point in chapters 1 and 4, showing that it is a possible policy option for CCSF if it forms a muni to use it as a net-revenue source. But we emphasized that the correct treatment in this study is to assume that the muni pays only the same level of in-lieu fees as PG&E's CCSF taxes would be -- for, to assume otherwise artificially burdens the muni option with higher costs and rates, and thus makes it look less attractive. Thus, this criticism is also contrary to other claims made that a muni would lower rates, for implementing the proposed measure would increase them.*

69) All these factors could contribute to lower electric rates for local consumers; however, they are not objectively factored into the ETAG study.

Response: *As the foregoing list shows, Mr. Ventresca is wrong on each item above, and thus also on this summary conclusion. Moreover, he is wrong about the effects of some of these items: the last one and others would raise rates, not lower them. And, as the answers above show, we directly incorporated savings into our rate and economic numbers where appropriate on specific items, benefitting the muni option..*

70) ETAG did not identify all the savings that ratepayers could derive from a public power system.

Response: *Again wrong. If this criticism refers to the above list, it's also again repetitious. If it does not refer to that list, then it's again an assertion without even any recognition of the logical burden to provide evidence.*

71) All of these positive benefits, according to ETAG's limited perspective could lead to zero ("0") savings for the consumers in San Francisco. ETAG's position does not make economic sense.

Response: *This claim is wrong on its face. As the responses to the above list show, we gave each of these items its appropriate weight. For the whole list, the quantitative effect we gave for these items exceeds the total rate savings (3%) and the total economic benefit (6%), thus offsetting the specific disadvantages to the municipalization option that Mr. Ventresca does not mention.*

72) ETAG Underestimates Savings

Response: *As the answers above and below, as well as the report as a whole show, this is simply wrong. As the report notes, if it errs at all in quantitative estimates, then it does so in favor of the muni option. This point was also made more than once in TRC discussions with Mr. Ventresca.*

73) ETAG falsely claims that "nationwide muni rates are 14% lower than IOUs, rates" (copy of slide ETAG distributed at the January 7, 1997 PUC meeting).

Response: *As chapter 1 notes, and so did TRC discussions of material now in the workpapers volume, we used the same data source for these numbers as does APPA: annual reports to the federal government by munis and IOUs. Once again, the item is just another bald assertion without any attempt at proof. But moreover, in view of the source of our data, this point is clearly wrong on its face. Most importantly, the allegation of "falsely claims" ignores that the APPA data show the same results as do ours.*

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74) Residential customers of public power utilites paid average rates that were 24% below those paid by customers of private power systems in 1994. And commercial customers of public power systems paid 15% less for electricity than IOU customers. This is according to the lastest national data kept by the federal government (Public Power Annual, APPA, Jan./Feb. 1996).

Response: *As explained in the rest of this response, the implication of this comment -- that there is some error in our report of a 14% differential, or that such a differential does not adequately characterize the muni/IOU experience -- is false. First, this is another example of Mr. Ventresca's reporting only part of the facts and ignoring the rest. Using two categories ("residential" and "commercial") is designed to make it appear that his account is complete -- and then because the figures for both parts are lower than the figure we reported for the total, the total we reported must be wrong. What Mr. Ventresca omits is that there is a third major category, "industrial", and the muni/IOU difference for it is over 8% in the other direction -- i.e., the average muni industrial electric rate is more than 8% higher than the average IOU electric industrial rate. Indeed, then, when all three figures are folded together, the average*

overall difference in favor of munis is 14%, not the 15% to 24% range suggested by Mr. Ventresca.

Moreover, it is not as if Mr. Ventresca was not aware of this matter, for the full set of figures is reported at page 10 of the workpapers volume. This reporting of the same numbers verifies that we used the same source for the data as APPA, which both of us cite. Further, Mr. Ventresca was not caught here by something added at the last minute or placed obscurely. First, his secondary source for the data, APPA, reports both the industrial and total figures just as prominently as it does the residential and commercial figures -- in fact, side by side. Second, the initial draft of our report included all this material in the body of chapter 1, and it was discussed with Mr. Ventresca at a TRC meeting. In fact, at that time, he objected to the inclusion of the industrial results, because they might provide argument for the anti-muni partisans.

There are particular reasons why the final text reports only the overall figure and not the user-class figures. First, the differences between class may be eroding over time because they are determined by local policy that is being disciplined by new developments in the electric-utility markets. Second, in any event, the rate structures will be policy choices for CCSF if it elects the muni option, and thus the results for other munis are not really probative, while the total difference does provide a useful guide because it does not reflect possibly declining local policy choice in that manner. Finally, as stressed in chapter 1, the results for existing munis v. other IOUs do not determine what will be the results for CCSF v. PG&E -- and that is what our report addresses.

75) Rates for public power customers have typically remained well below those of customers served by investor-owned utilities since federal comparison statistics began to be published after World War II, over 50 years ago.

Response: *This criticism, too, seems to suggest that our report claims to the contrary, or is somehow otherwise erroneous or misleading on this point -- especially when read in conjunction with items 73 and 74 above in this section. Well, that is completely wrong and misleading. In fact, what Mr. Ventresca fails to acknowledge this time is that our data reports this same point, with graphical quantification and specific to California. See Figure 1-4 at page 1-12. We reported the facts accurately and did not underestimate the savings, Mr. Ventresca's allegations to the contrary notwithstanding.*

76) Folsom Condemnation Case

Response: *This section has many of the same characteristics as the previous section: artful use of half-truths leading to false accusation.*

77) In 1989 Mr. Knecht, the primary author of the SF Municipalization ETAG report and President of ETAG, played an instrumental role in the largest condemnation case in California in the last 17 years as a PG&E contractor (Sacramento Municipal Utility District (SMUD) v. PG&E; Sacramento Superior Court Case No. 322521).

Response: *Contrary to the tone, nothing in this statement is new or in any way contradicts anything said in our report or in any other part or aspect of this project. Mr. Ventresca neglects to mention that this item was first referenced in our Proposal, where a full paragraph on it at the top of page 5 set out the relevant facts. Actually, the artful use of dramatic vague language suggests more here than the facts, which are that Mr. Knecht was retained by PG&E to prepare a valuation using the income-capitalization model, and after being designated as a witness, was deposed by a SMUD outside attorney for the case. As do most such cases, the matter settled before trial, after the parties took each other's measure in pre-trial activities. But that doesn't make as good a tale as does "played an instrumental role". As for this being the largest condemnation case, Mr. Ventresca neglects to cite a source: the only one that exists, to our knowledge, is the survey we prepared for this project and which is included in the chapter 2 workpapers. Note, however, that this survey includes only electric-system condemnations involving California's three major IOUs; it does not purport to be and surely is not a basis for reaching a label as "the largest condemnation case in California in the last 17 years."*

78) The case demonstrates Mr. Knecht's propensity to inflate the valuation of an electrical distribution system during a condemnation proceeding.

Response: *It demonstrates nothing of the sort. Instead, it demonstrates Mr. Knecht's skill and experience in making a valuation using one of the two valuation methods favored for these purposes by California law, and the one that yields the lowest legally admissible valuation here -- as discussed in chapter 2. It also demonstrates his familiarity with the utility condemnation process in California, with the PG&E system, and with PG&E as a corporate entity and with its Legal Department practices in particular -- all of which is very valuable to this project. Mr. Knecht has done more work for munis than for PG&E and other IOUs as have other ETAG Team members, (another fact Mr. Ventresca continues to ignore, after being reminded of it many times).*

79) Mr. Knecht, who was.one of three consultants for PG&E in this case, came up with the most inflated value of the electric distribution system SMUD was trying to take over in Folsom.

Response: *Mr. Knecht's valuation estimate was the highest of the three, but was not at all inflated; the order was a result of the particular facts of that case, just as the order of the valuations in this case would be a result of its facts. And, as noted, the capitalized-income method here produces the lowest admissible value by a wide margin; we suggest that it is the single best value here. Moreover, another fact Mr. Ventresca omits is that his own preferred consultant. Mr. Wilson, stated in interviews with the Commission and TRC that he prefers the income method, too; as discussed in response below to item 102, Mr. Ventresca's account of Mr. Wilson's electric-system valuations this last year, Mr. Wilson also gets values above the depreciated original cost, as do we.*

80) PG&E legally argued in court, using Mr. Knecht's Income Capitalization analysis, that the system was worth $51.4 million. Eventually, the value was determined to be only $13 million.

Response: *Actually, PG&E argued no values in court on this matter because the case settled before trial. It is fair to say that PG&E was prepared to argue a range of values up to $51.4-million. But Mr. Ventresca understates the actual valuation by 30%, for in taking compensation figures from our workpapers table, he forgot to check for payments subsequent to the initial one, and there is a second payment of $5.4-million there for this item. Mr. Ventresca missed the point that the settlement was based on PG&E's estimates of replacement costs, which were much higher than SMUD's and higher still than the estimates SMUD prepared of the depreciated original cost. (So much for Mr. Ventresca's favorite valuation theory; it's not only not likely to get into the record as a legitimate valuation estimate, it is also greatly exceeded in cases that munis settle.) In view of the outcome of the Folsom case -- being crafted around the RCLD + GCV + PS valuation -- he should have embraced our base-case ($795-million) and upper ($999-million) estimates as the likely outcome range here to be consistent with the result he celebrates.*

81) SMUD attorneys argued convincingly that Knecht's work for PG&E "manufactured sums", used "improper" economic analysis techniques, and violated the California Evidence Code. SMUD attorneys could find no case or statute that required a public agency to pay the inflated value Knecht came up with. They concluded Mr. Knecht's findings and testimony had "no legal support" and sought to remove Mr. Knecht's prejudicial evidence from the record. (See SMUD's Motion in Limine filing for this case dated February 15, 1989.)

Response: *Again, Mr. Ventresca reports a half-truth: of course SMUD's lawyers sought to bar (not remove) adverse evidence from a witness they feared after deposition might prove persuasive to a jury, and of course they alleged such notions in seeking to bar it; what Mr. Ventresca doesn't report is that they failed to bar it because (as discussed at length in chapter 2) the nub of their claim on legal support, etc. was completely wrong. The conclusion that counts here is not SMUD's that lost, but rather the court's.*

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82) In otherwords, Knecht served as a hired gun for PG&E, came up with the highest valuation figures of all consultants involved in the case, and used questionable and improper economic analysis techniques to inflate the numbers for PG&E. (The Income Capitalization analysis was also utilized in the SF ETAG report and is identified as the so-called "Low" case ($505 million) valuation.

Response: *What actually happened is an example of the process we discuss in the Executive Summary, as well as chapters 2 and 5, and the relative ranges of figures and risks encountered in it. His denigration of the income-based estimate of $505-million as a "so-called 'Low'" seems bizarre, though, given not only Mr. Wilson's (and California law's) reliance on income methods, but also the fact that the alternatives begin at $290-million higher and run to half-a-billion dollars higher or more. Mr. Ventresca overlooks that our use and support of the income method here is made more credible by being consistent with Mr. Knecht's use of it in the Folsom case.*

Mr. Ventresca also apparently misses the fact that electric industry restructuring has made the replacement-cost alternative much less attractive than it used to be, because charging of CTCs now saddles this method with full stranded costs, where it was not so burdened before. On the other hand, CTCs make no difference to the income methods, because as we explain in chapter 2, they properly already included rate-recoverable excess (now "stranded") costs directly; the only change, as we noted, is that, to avoid double counting, the revenues in the income analysis must be reduced now by not including the stranded costs (as we did not) that will be recovered under the CTC. Thus, the income method has become systematically more attractive to muni advocates than it previously was in comparison to the other admissible option.

The Range Between "High" and "Low"

83) The gap between the high ($1.5 billion; orally brought up by Mr. Knecht at the 1/7/97 PUC meeting) and low ($300 million) valuations for the electrical distribution system in San Francisco is extremely large.

Response: *First, this mischaracterizes our position, because our low estimate remains $505-million and our high estimate remains $999-million -- for a difference of less than 100% of the lower value (or less than 50% of the upper value). The $300-million (actually $315-million) figure is our estimate of the depreciated original cost, which we have noted from the start is not admissible as an estimate of the value per se in California. The $1.5-billion ($1.456-billion) is our updating of an old PG&E estimate; it was provided only in response to a request from Commissioner Makras concerning possible upper limits, and we believe the correct value of the RCLD(SF) + GCV +PS value is $999-million, not this $1.456-billion estimate.*

On the matter of the relative gap between these figures, Mr. Ventresca's criticism ignores what he was told from the start in this project and what experience has shown the professionals in these matters. The range of estimates in the Folsom case he cited above was relatively larger, with the high estimate being about seven times the low one, not just five times as here. Second, we discussed the likely range in our interview with the TRC, including Mr. Ventresca, in terms of the relative span of the Folsom figures being representative. In addition, we also recall Mr. Ventresca's favored consultant, Mr. Wilson, discussing it, too, and he mentioned a possible span factor of ten! Thus, with a factor of less than five, and certainly with a factor of less than two, as shown by the numbers we support, the variability of our estimates is well within the mainstream.

84) This means that the basic findings and major conclusions, in the ETAG report, should not be relied upon to make a public policy decision on the public power question.

Response: *As the foregoing response to item 83 shows, Mr. Ventresca should know that the standard he seeks to apply to our study would rule out any study that assesses the reasonable and likely range of figures that parties may present. The point of the study is to assess the range of likely and reasonable outcomes. Our assessment of the relevant range here adds information that is essential in making an informed policy decision, and an insistence on a small range would be rejection of necessary information.*

85) ETAG's Fundamental Bias Against Public Power

Response: *We stated from the outset that we have no bias in either direction, and in fact we think that it is a point of qualification in a business where consultants work mostly one side of the market or the other. This claim was backed up by the fact that we have worked for both sides (as Mr. Ventresca always omits) -- which one can do only by providing objective analysis, not viewpoint-driven estimates -- and we have done more work for the muni side than for the IOU side, as we emphasized from the start. Further, our quantitative results here favor the muni option, and we stated at the 7 January meeting that they are systematic and significant in that direction, and the option should thus receive serious consideration. The charge of bias is contrary to all the facts.*

86) In the second draft of the ETAG report (December 9, 1996, page 4-25), the text states: "Which is more efficient on average, the public or private sector? ... The whole of world experience over many decades supports, we firmly believe, the answer that the competitive private sector is more efficient."

Response: *Yet again, only a part of a quote is taken completely out of context. Here is the whole text: "The question here is not: Which is more efficient on average, the public or private sector? If that were the question, the whole of world experience over many decades supports, we firmly believe, the answer that the competitive [the key word] private sector is more efficient. The question is a comparison of municipalization (classic socialization) of electric service with the U.S. alternative of monopoly franchise and state regulation." We concluded the footnote, which this statement began, by saying: "Thus, the question is: Which works more efficiently (or, more generally, "better", however defined), direct political control of the operation or political control of a private provider which owns and runs the operation? It is on this question that there is no definitive analysis or evidence, only a range of experience on both sides."*

Our view on the relative efficiency of the competitive private sector versus the public sector is more than fully within the mainstream of economic thought; it's the overwhelmingly dominant view. Moreover, the point of the footnote was to emphasize that the muni/IOU question lies completely outside that historic debate, and must be addressed on its own terms. Thus, in the middle of the footnote, we emphasized that the electric sector is one that cannot be provided on a competitive basis by the private sector; it is a "natural monopoly" and there is no competitive market alternative available for the electric distribution system. Thus, our point was that this issue can't be decided by appeals to broader ideological views, but must be decided on its own terms -- and best done with feasibility studies and related policy analyses such as these.

87) Any professional consultant who has this worldview should never have been awarded a contract to analyze the public power option. And any professional team of consultants who held this view would have their professional judgments influenced by this profound and fanatical bias.

Response: *In view of the previous answer, in this statement Mr. Ventresca clearly wants to rule out anyone with the overwhelmingly dominant views of the economics and public policy*

professions and anyone who calls for the broader ideological issues to be left at the door so that this issue can be decided on the merits and on its own real-world terms. We think that a view based on the facts specific to this issue, not on extraneous ideology, is essential. Thus, this criticism, too, is 180 degrees wrong.

88) ETAG inappropriatedly and carelessly has used extremely high end figures that are based on nothing more than wild speculation. In the December 9, 1996 draft of the ETAG report (2-42), the text uses a,"$1.4 billion" figure.

Response: *This figure is also taken completely out of context to make it appear to be the opposite of what it is. It was listed as an updating of the 1982 PG&E estimate for RCLD(SF) + GCV + PS. As we noted in response to item 83 above, in the revised text and in discussions with Mr. Ventresca in the TRC meeting, we do not support this figure -- and in fact our estimates refute it. It was provided as sober guidance for what PG&E might claim, which we think is essential information for an informed decision. Despite these essential points having been made to him and despite the derivation of the estimate having been made clear in the text he cites, Mr. Ventresca tries to cast this as an estimate we support and labels it "wild speculation". Clearly, this is not serious constructive contribution.*

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89) At the January 7, 1997 presentation before the PUC, Mr. Knecht used a "$1.5 billion" figure. There is no credible evidence in the record or in this report to justify these figures.

Response: *This is a repeat of the same issue as discussed in response to item 83 above, here with $1.456-billion rounded in the 7 January discussion to $1.5-billion. Anyone listening to the tape or attending that meeting and familiar with the earlier estimate would hear that clearly.*

90) Key Documents Missing From the Record

Response: *Most of these points have been raised before and answered in writing, as well as discussed with Mr. Ventresca at TRC meetings and otherwise -- and he again fails to even acknowledge, let alone start to answer, the responses he has been given. None of these points are relevant to the quality and validity of the report.*

91) There were two serious violations, by ETAG, of mandatory requirements in the PUC's Request for Qualifications (RFQ) Manual in regards to this contract. ETAG neglected to submit with their April 26 proposal:

Response: *There were no violations, and the following two specific responses show that Mr. Ventresca mis-states this matter, too.*

92) 1.) a copy of a publicly available municipalization feasibility study that had been completed in the last 10 years; and

Response: *This item has already been answered on paper for Mr. Ventresca, but he fails to even acknowledge that. Here, copied from page 18 of our response to TRC comments (page 241 of the workpapers volume) is the answer again: "ETAG submitted the Memphis study, in which its team leader and another member were key participants and co-authors. Memphis has a distribution muni and was considering municipalizing its energy supply, instead of continuing to purchase from a single supplier. SF has a municipal energy-supply operation and is considering municipalizing its distribution system. Thus, these two projects are comparable. In addition, another team member has done municipal feasibility studies for Chicago, which were made available to CCSF within the confidentiality restraints set by Chicago, as his client. By themselves, either of these items would satisfy the requirement (if the specification of these documents is truly a requirement, and not merely a desirable indicator of experience.) In any event, ETAG also submitted other relevant experience covering all elements of this study, with the vast majority of that work for munis."*

93) 2.) a copy of background financial data on their firm.

Response: *Item h at the bottom of page 12 of the RFQ requires such financial statements as are available, and we submitted those which were available for Cerbatos & Associates, a joint-venture partner in the proposal. ETAG does not prepare financial statements, for it has no need of them and no legal requirement to do so. Recently, HHW&P Staff contacted us about this item, in response to an inquiry to them from Mr. Ventresca. We provided the reference to the Cerbatos form, which apparently had escaped notice among the attachments, and to the terms of the RFQ. We understand that they provided the information to Mr. Ventresca.*

94) These documents were never produced and were never made a part of the public record.

Response: *Not true, as shown above -- and as Mr. Ventresca knew.*

95) I have seen no evidence to date that any member of the ETAG team has ever worked on a successful municipalization on the public power side or that any member of the ETAG team has ever produced a published, available municipalization feasibility study prior to their current flawed effort. It is clear that ETAG misrepresented its municipalization feasibility study experience and its PG&E connections before the contract was awarded.

Response: *The above answer to item 1, previously provided in writing to Mr. Ventresca (as well as being discussed by telephone and in TRC meetings with him), plus the third following answer (involving Mr. McQuat's role) shows that the required documentation has been timely provided as required by the staff and reviewed and found adequate by it for this contract. In fact, Mr. Ventresca studiously omits to tell that Mr. Knecht personally provided to him at the outset of this project all of the material not covered by confidentiality agreements with previous clients (which*

was provided on a more limited basis to Staff) -- a large stack. Contrary to Mr. Ventresca's claim, this material fully demonstrates qualification for this work and compliance with The City's requirements. Mr. Ventresca is merely seeking to alter the requirements in order to exclude all bidders but his preferred consultant. The last sentence of this criticism is knowingly untrue, as shown by the materials provided to Mr. Ventresca and discussions held for his benefit, and as summarized in answer to some of these items (e.g., response to item 92).

96) On December 16, 1996 before the PUC Technical Review Committee (TRC), Mr. Knecht disclosed for the first time that he had possession of the Folsom condemnation-related deposition he completed for PG&E in 1989. As a member of the PUC TRC, I asked him to disclose this document. To date he has refused to do so.

Response: *It is false to claim that Mr. Knecht disclosed this for the first time on that date, for it was known from the beginning of the project, and Mr. Knecht mentioned more than once in the ordinary course of business that he had located his copy. In fact, a local newspaper has referenced it, proving that it has not been at all hidden. What Mr. Ventresca sought and was denied on 16 December 1996 was the same kind of special treatment he had previously been given, as compared to all other TRC members: the use of ETAG's resources for his personal crusade. ETAG has agreed that, if Staff determines at some time that this item is needed, it will provide a master copy for Staff's unlimited use -- but, in view of the facts, no need has been found. This is a completely disingenuous and harassing criticism.*

97) On or before October 29, 1996, Mr. Knecht produced a detailed memorandum defending the ETAG report for Arthur Bruzzone, the producer of a cable television public affairs program called SF/Politics. Again, as a member of the PUC TRC, I asked Mr. Knecht twice to disclose this document. To date he has refused to do so.

Response: *Mr. Ventresca either has a copy already, or he is speculating about its contents. In any event, the whole matter is irrelevant, because this memo was not at all produced on City time or in any way as an official document under this contract. It was a summary of points for a television producer who did not want to have a one-sided show, and wanted the facts.*

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98) On October 16, 1996 at the PUC TRC, Mr. Wallace McOuat, a member of the TRC and a consultant to Mr. Kline, disclosed for the first time that he had been provided documents on ETAG's background which he reviewed and subsequently returned to the City Attorney's Office months before. He informed me he did not retain copies of the documents. These documents have never been released. They should be released now.

Response: *This decision is completely in The City's hands, and no further comment from us is needed or appropriate -- except that we stand ready to do provide one copy of any of these materials requested by the City for whatever purposes it deems appropriate.*

99) At the last meeting of the TRC on December 16, 1996, 1 asked Mr. Knecht to provide copies of all documents or parts of documents (for example: correspondence, memoranda, relevant parts of reports, APPA documents reviewed, etc.) that were used by ETAG to produce their report to the PUC so the public could have access to these documents in the future. Mr. Knecht would not commit to provide this material to the PUC department. The PUC should direct ETAG to transmit these materials to ihe department prior to any final payment on this contract.

Response: *This comment also mis-states the matter completely. Upon Mr. Ventresca's request essentially for a complete office search and file dump of everything we might ever have read or possessed, this matter was discussed, and a reasonable scope of everything useful to understanding and evaluating our report was agreed to. It was provided in the 265-page workpapers volume (on top of the voluminous material previously provided along the way). ETAG has provided all relevant materials for this project, contrary to Mr. Ventresca's claims.*

What Might Have Been

100) The PUC Commission rejected the one qualified consultant, who had experience doing municipalization feasibility studies and experience establishing successful municipalizations, who had no PG&E ties, who had met all the requirements of the RFQ, and who had been overwhelmingly recommended by the TRC, Wilson and Associates.

Response: *Mostly, this complaint addresses the action of the Commission, and we want to avoid arguing about a competitor's qualifications here. However, one comment is appropriate, because it bears on Mr. Ventresca's credibility. Above, he railed incontinently about "serious violations by ETAG of mandatory requirements [in the RFQ]" because ETAG does not have financial statements and submitted that of its joint-venture partner as maximal and good-faith compliance to the best of our ability. Here he how claims that Wilson and Associates "had met all requirements of the RFQ". We won't give a detailed account of shortfalls in the Wilson proposal, but we do note that it absolutely did not meet all the requirements: there were no financial statements, nor any reference to their absence. This demonstrates Mr. Ventresca's bias, double standard and disingenuousness again.*

101) The PUC Commission instead hired an unqualified and conflicted consultant, who had no experience doing municipalization feasibility studies and no experience establishing successful municipalizations in the public sector, who had performed $140,000 in contract work for PG&E, who had not met significant mandatory requirements of the RFQ, and who had not been ranked as the consultant best abled to perform this contract by the TRC, ETAG.

Response: *These characterizations of ETAG are false, as explained above, and since this item is just repetitious and is directed at the PUC, we will say only one other thing in response to it. Mr. Ventresca studiously avoids mentioning that, on the same basis as the $140,000 figure was developed (all billings of all projects, including mainly at other firms than ETAG and including many billings not made by any of our team members), in which any of our team members were*

involved over the last decade -- on that basis, the total for munis and active PG&E opponents is seven times as large (over $1,000,000). It has been explained many times to Mr. Ventresca that: 1) the $140,000 figure is a gross over-statement of the relationship to PG&E and other IOUs; 2) the 7:1 ratio suggests that, if anything, a concern about bias would be bias arising on the pro-muni side because that's where 88% of the dollars have been found; and 3) anyone who hasn't worked for both sides is biased, not those who have. He has no answers to these obvious and sensible points.

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102) Wilson and Associates, after the SF PUC turned this firm away, went on in the past year to complete two municipalization feasibility studies for two cities (Canton and Potsdam) in New York State that showed savings of 25 to 40% if those cities converted to public power systems. Two other independent consultants in New York State (R.W. Beck and Cohen, Dax, Coenig & Wiles) verified Wilson and Associates high quality, credible work by completing municipalization feasibility studies for other nearby cities and finding the same levels of savings as Wilson and Associates had.

Response: We have reviewed the J.W. Wilson study, dated August 1996, on the feasibility of municipalizing electricity service in the towns of Canton and Potsdam in upstate New York. These two towns, which contain 9,901 electric customers (3% of SF's customer total) who use 203,788 MWh, currently receive electricity service from Niagra Mohawk Power Corp. (NIMO). ***The Wilson study shows that all of the 24% annual savings under the municipalization scenario are related to power cost savings. In fact, without power cost savings the ratepayers would pay more under municipalization than continued service from NIMO.***

The 24% annual savings are only possible, according to the Wilson study, if a three mile transmission line is constructed in order to bypass all NIMO transmission facilities and reach a low-cost state (or other) public power provider with power for sale. Without the transmission line, these two towns would have to pay NIMO for its stranded costs. If these two towns were located further from the border of NIMO service territory, municipalization would not be feasible. Neither of these options are available in California.

As to certain assumptions in the Wilson study that may be related to ETAG's feasibility study, we find that J.W. Wilson assumed the interest rate on municipal bond financing would be 9%. ETAG assumed 7.5%. ***If ETAG used the Wilson muni-finance assumption, the annual financing costs under the municipalization scenario would increase by 20% and reduce this would reduce net municipalization benefits in ETAG's Base Case scenario by 80%. We also observed that Wilson did not assume that NIMO's distribution assets could be taken at net book value but at a value above net book value, somewhere between the income method and RCNLD, as do we here. Wilson also concluded that FERC would impose stranded costs on a municipal entity that municipalized and then attempted to wheel purchased power over the existing utility's transmission facilities.*** *This outcome would be identical to CCSF's case.*

The Wilson study assumed development costs, not including the cost of distribution or transmission facilities, to implement the municipalization of $5.64 million or about $570 per

customer ($5.64-million/9,901customers). If this same per-customer cost of development were used by ETAG in its study, total development cost would approach $200 million ($570 x 350,000 customers) instead of the $15-35 million assumed by ETAG.

The following analysis of the J.W. Wilson study of the feasibility of municipalization for the towns of Canton and Potsdam is the basis for the preceding conclusions:

NIMO's average rate per kWh is 10.45 cents and J.W. Wilson estimates that average rate per kWh under the municipalization scenario is 7.90 cents per kWh (page v of the Wilson study). Total annual electricity costs with NIMO are $21.3-million (page 62 of the Wilson study). Total annual electricity costs under the municipalization scenario are $16.1-million (exhibit 8 of the Wilson study). Therefore, total annual savings for both Canton and Potsdam under the municipalization scenario are estimated at $5.2-million, or 24% (page vi of the Wilson study).

Of the total $21.3-million in annual NIMO electricity rates billed to customers in Canton and Potsdam, power costs represent $12.8 million and transmission related costs represent $1.3-million for a total of $14.1-million (Exhibit FDC-2 of the Wilson study). In order to avoid NIMO stranded-cost charges that FERC would impose if the two towns used NIMO transmission facilities, the towns of Canton and Potsdam would build a 3-mile transmission line which would interconnect with the Power Authority of New York grid (page ii of the Wilson study).

The annual costs for purchased power, PASNY wheeling and transmission capital related costs would total about $7.5-million (purchased power and wheeling costs are taken directly from Exhibit 8 of the Wilson study. Transmission related costs, depreciation and interest were calculated by ETAG based on the data in Exhibit 8).

The difference between NIMO's annual power costs and transmission related costs of $14.1-million and the municipalization scenario of $7.5-million is $6.6-million which is 120% of the $5.2-million in savings. The annual cost of the distribution function is therefore ***higher*** *under the municipalization scenario than under continued service from NIMO according to the Wilson study.*

	NIMO	Municipalization	Difference
1. Total Annual Electricity Costs	$21.3-million	$16.1-million	$5.2-million
2. Power and Transmission Costs	14.1-million	7.5-million	6.6-million
3. Distribution Costs	$ 7.2-million	$ 8.6-million	($1.4)-million

The interest rate on municipal bonds issued to acquire the NIMO distribution system and to finance construction of the transmission line is detailed on page 58 of the Wilson study. The development costs of $5.6-million, which consists of legal engineering and other expenses incurred by the Wing Group up until the time that the municipal system is established is detailed on page 53 of the Wilson study.

103) On the other hand, over the past year, ETAG prepared a long overdue municipalization feasibility study that showed only 0-5% savings.

Response: *The account above shows that, leaving aside the unique PASNY bypass option to which there is no equivalent opportunity for SF, the effect of municipalizing would be a 6.6% increase -- where we found a 6.4% decrease for SF. That is the fair and accurate comparison of the two studies.*

104) Conclusion and Recommendations

Response: These items mostly restate previously repeated claims and leap to unfounded conclusions, so we will not attempt to repeat the detailed answers given above.

105) The one-sided, unfair, subjective, narrow, erroneous, misleading, and anti-public power ETAG report is irreversibly biased and flawed.

Response: Not so, as demonstrated by the answer to every point.

106) The misinformation, in this report, is overwhelming.

Response: See the response above to item 105.

107) If it is not rejected and refuted, it will jeopardize the City's legal and economic interest-- in the public power area-- for years to come.

Response: As shown in these responses and in the report, the ETAG report provides a sound basis on which to make the overall policy decision on this matter and protect the full range of interests of the people and City of SF.

108) The ETAG study was prepared by an unqualified and PG&E-connected contractor that used unethical and fraudulent means to win the contract.

Response: This is incorrect in all its particulars, and maliciously so stated.

109) The PUC Commission, intentionally or unintentionally, hired a pro-PG&E consultant that has documented all the reasons why the PUC should not consider the public power option seriously.

Response: This item is mainly for the PUC to answer, but clearly Mr. Ventresca did not read our report, for it does not reach that conclusion at all.

110) The simple true is a PG&E-connected contractor produced a PG&E-friendly report which was written carefully to protect the century-old PG&E monopoly.

Response: Besides being ungrammatical, it's also simply, absolutely and completely wrong.

111) The Board of Supervisors passed Resolution 604-96, that became effective public policy on July 1, 1996, urging that the contract with ETAG be terminated. I concur with their adopted position. The PUC should immediately terminate the contract with ETAG and pass a resolution with appropriate findings rejecting ETAG's report.

Response: *If one were to use Mr. Ventresca's account (e.g., "has documented all the reasons why the PUC should not consider the public power option seriously") as our results, then we would agree. But, as noted above, that account is 100% wrong. Thus, instead, the PUC should adopt a resolution adopting the report as its findings and forward it to the Board as its report.*

Page Fifteen

112) In addition, I recommend that the City Attorney, District Attorney, Ethics Commission, and the Board of Supervisors investigate the fraudulent means that ETAG used to improperly obtain this contract.

Response: *The allegations of fraud and improper action have been shown here and many times over to be untrue, and they are simply malicious defamation without even an attempted justification.*

APPA's Letter-review of ETAG's San Francisco Electric Municipalization Feasibility Study – and ETAG's Response to It; 31 January 1997 – APPA's text in Times New Roman; ETAG's Responses follow each paragraph in italics.

APPA

American Public Power Association

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January 22, 1997

Lawrence T. Klein
General Manager
Hetch Hetchy Water & Power
City of San Francisco
1155 Market Street
San Francisco, California 94103

Dear Mr. Klein:

APPA has received a copy of the Economic and Technical Analysis Group (ETAG) *Preliminary Feasibility Study of Electric-System Municipalization for San Francisco Public Utilities Commission*, dated December, 1996. We are disturbed by ETAG's misuse of APPA materials in the report. In offering this limited comment, we urge the Commission to be mindful of these distortions of fact in its review of the ETAG study and its conclusions.

Response: There are no misuses or distortions, as the discussion below of the detailed points makes clear.

APPA stands by the information that it produces, sponsors and distributes. ETAG's misuse of the information provided suggests a fundamental lack of understanding of the difference between public power and privately owned utilities, and a failure to systematically and fairly review findings on relative efficiency of the two sectors.

Response: As noted above and demonstrated below, there are no misuses. Therefore, there is nothing to suggest any such lack or failure. These are just attacks on us and our conclusions. Our response sticks to the substantive matters and will not engage in that kind of argument.

The ETAG study uses a statement in APPA's *The Value of a Public Power Distribution System: Increasing, Not Decreasing* to confuse the valuation issue. There, the author states that net book

value or original cost less depreciation (OCLD) is not a correct value for a municipal electric-utility distribution system in the emerging market: the amount should be much higher. ETAG's fundamental error is that it applies this statement about public power distribution systems to the valuation of investor-owned utility systems. This is an apples-to-oranges comparison. Original cost less depreciation is not the proper method for valuing a public power utility, but it is the proper method for valuing investor-owned utility property.

Response: We agree that OCLD is not correct for valuing muni utility property, and that the amounts should generally be much higher. We derived our view that OCLD is not proper and that the income-capitalization and RCLD + GCV + PS values are correct from fundamental economic and policy analysis, as well as review of legal precedent; our development of this position in no way depended on any APPA analysis. (We merely cited an APPA paper as coming to the same conclusion, at least for munis, and we indicated that the reasons given therein support our view; we continue to so hold, despite these comments.) Section 2.A of our report explains in detail the economic and public-policy reasons that OCLD, per se, is invalid as a valuation measure for IOU property, as well as for any other; these reasons do not depend on the identity of the owner, and in fact are not affected by it at all. That section also explains that the law in California and generally in the United States recognizes our viewpoint on this matter; we are unaware of any state that follows APPA's views on this matter, and it has cited none. Thus, contrary to the allegations, we made no error, there is no confusion on our part, there is no apples-to-oranges comparison, and APPA's view is still wrong on this matter.

As public power utilities are public entities, the physical assets are owned by the community. In contrast, the financial commitment of a private utility's investors is not its physical assets, but dollars (or original cost less depreciation), as reflected in the rate base. The stockholders have invested capital and are entitled to a return of and a return on their investment. Over time, an investor-owned utility's stockholders have routinely recovered capital invested through depreciation charges and annual profits allowed by state regulatory commissions. When the property is sold and removed from the company's accounts and rate base, prior to full depreciation, compensation equal to the property's remaining net book value will make the company and its stockholders whole. Anything more than this would be a windfall profit to investors.

Response: The basis for the claimed contrast between the two systems in the first two sentences is impossible to discern and certainly not economic; in fact, the claim itself is vague, but mainly irrelevant here. The rest of the paragraph is correct until it makes a critical error in claiming that net book value will make the company and its stockholders whole, and further that anything more is a windfall profit. This is not so in California or any other utility regulatory jurisdiction of which we are aware (and we have practiced extensively across the country, including nearly all major states and well more than half of the total). As we explain in section 2.A, area-averaged rates, required in almost all cases, allow and in a very real sense require some assets to earn much more than the system-wide allowed rate of return on investment (and others to earn

less). As we also explain there, taking of these assets from a vertically integrated utility can have the effect of diminishing the value of other assets vertically upstream from the taken asset -- i.e., which rely on the taken asset as a market gateway, and which are thus stranded not for any reason but the taking of the gateway asset. California law has long recognized these two effects and requires compensation for them, as does that in other states so far as we are aware. APPA's valuation position in this letter is based on generic assertions on this matter that do not track real-world regulated IOU ratemaking or takings law. As noted in the previous response, our reliance jointly on income and replacement-cost analyses is supported in law and economics.

In regard to the evidence in the paper prepared by Professor John Kwoka, Jr., the ETAG analysis ignores the paper's central findings. While certain public power costs are important factors that help explain public power's lower rates, "public ownership is still responsible for over 50 percent of the apparent price difference" between public and private electric systems.

Response: *This is clearly a misreading of our position: we did not ignore this finding, but considered it thoroughly and firmly rejected it because it is the product of an erroneous study -- and in fact, some or all or even more than all of the claimed effect may well be the fictitious result of the error. In any event, regardless of the amount of systematic overstatement of the purported effect due to this error, the study is characterized by a fundamental and pervasive specification error that deviates completely from regulated rate-setting practices for IOUs and that thus renders all its conclusions unfounded. As we noted in chapter 3, other analyses may in fact prove some of the tangential conclusions true, but this study cannot prove anything until this pervasive error is corrected. Note also that, before we published our criticism of Mr. Kwoka's paper, we called him to seek an explanation or defense. He was vague on the point and unable to offer any defense, but he said that he would contact us with an answer if he found anything salient on the matter. To date, he has not done so.*

This basic result was essentially restated in working papers prepared by Professor Kwoka for the Discussion Paper Series of the Harvard Institute of Economic Research, and in an Economics Discussion Paper for George Washington University. The Harvard paper states: "public ownership is associated with lower production costs and, moreover, for unit cost, price is significantly lower as well." And the GW paper concludes: "... Public ownership emerges quite clearly as associated with lower prices in this industry, holding constant all the other factors thought to play a role."

Response: *We reviewed these two papers, also, and found them to be disabled by the same error. Since they are derivative of the primary analysis in the first paper and share its key error, it is unsurprising that they come to the same conclusion -- and for the same reasons, they also do not add any support to it or produce any valid results themselves.*

Instead of focusing on these results, the ETAG paper focuses on one of the subsidiary findings in the paper regarding economies of scale in distribution and transmission service. This issue is

clearly not the main conclusion of Professor Kwoka's paper, nor is it the primary, or for that matter, the relevant issue, in the San Francisco municipalization debate.

Response: *This is a misreading of our work, for as we noted above, we focused first on the primary result and rejected it. We merely mentioned the other result for two reasons: 1) contrary to APPA's view of what are the issues in SF, economies of scale are important in this matter; 2) this provided another example of how those who promoted reliance here on this study did so only selectively, advocating reliance where it benefitted their views and non-reliance on the same study to the extent it did not benefit their a priori political views.*

ETAG criticizes the Kwoka study because, allegedly, "its common-stock profits variable has been defined and quantified ... to include only dividends and to excluded the roughly one-third of total profits that go into retained earnings." This criticism betrays the authors' bias against the formation of a new municipal electric utility. They fail to describe how this would -- even if it were in fact the case qualitatively and quantitatively change the basic conclusions of the study. This alone is sufficient for rejecting the ETAG criticisms out of hand.

Response: *As we noted above, because this is a major across-the-board mis-specification of a key variable, it invalidates the results of the entire analysis. This comment betrays a lack of understanding of statistical analysis, because it presumes that one can say (qualitatively or quantitatively) what the effect of such an across-the-board correction will be in a multiple-regression analysis; by the nature of such analysis, that simply is not possible. At an intuitive level, the error seems like it may lead directly to the claimed major result, and thus that result would be a fictitious result of the error -- but we do not even make that claim, instead we just recognize that it is certainly a real possibility. This explanation corrects the errors in the substance of this comment. The final-sentence conclusion is wrong, because it states that a diagnosis of a serious error in the analysis does not disable the result until some other result is proven -- but that is simply logically wrong.*

But there is the added fact that the basic conclusions of the Kwoka study have withstood the scrutiny of a national, non-partisan professional association and two prestigious universities. In contrast, the ETAG criticisms of the study have not even been clearly stated.

Response: *As discussed here and in our report, our criticisms have been very clearly stated; the problem is that APPA misreads the report and mis-states our positions, seeks to require a critique of a statistical analysis to do the impossible (correct the result without re-running the regressions with the right data), and responds to serious analysis with ad hominem attacks. In chapter 3, we note that, but for the error we found, this study appears at first to be well-conceived and executed. Another problem is that "having withstood the scrutiny", etc. is no defense against a designation of a clear and serious error -- i.e., it doesn't correct it or retrieve the discredited results.*

ETAG criticizes APPA's booklet, *Straight Answers to False Charges Against Public Power*, for failing to clarify that one of the Hausman and Neufeld studies cited is an historical review of economic literature, rather than a modern day study. This is true, but the study is only one of many cited that refute the charge of public power's lesser efficiency. In fact, the very next sentence in the booklet says "In a 1990 study, the authors [Hausman and Neufeld] looked at recent studies that used more sophisticated econometric methods and found that seven of nine showed either no significant efficiency differences or greater efficiency for publics."

Response: First, it is important to note that this paragraph admits our main point, that the APPA paper misleads ("failing to clarify" at least) the reader on a key point. Second, this paragraph obfuscates by responding to something we didn't say: nowhere in our estimates did we assume anything akin to "public power's lesser efficiency" and in fact, we assumed that its efficiency would be the same as that of PG&E. Finally, it refers to another Hausman and Neufeld study, this one done for APPA and not published in the peer-reviewed literature, as was the one we cited. Below, in response the full citation of that other study, we respond to it in detail.

Straight Answers to False Charges Against Public Power is a popular publication for a general audience and one of its purposes is to provide the reader with pointers to primary sources. Clearly the ETAG authors show their bias by focusing on one sentence in this booklet, while ignoring the content of primary source academic studies available to them through APPA or in their own review of the economic literature.

Response: First, we do not think that inclusion of misleading material is acceptable for "popular" documents – i.e., those that will get the greatest public exposure to "a general audience". Second, the comment misrepresents our position: our criticism was that this is an example of the misleading material in that publication. As another example, we showed that the claim at page 3 that munis "[a]re not for profit and do not pay dividends to near or distant stockholders" fundamentally misleads, because for each dollar financed, the muni interest payment is roughly equal to the IOU interest-plus-dividend payments; moreover, in a takeover, the muni must finance more dollars than did the IOU for the system, because the muni will pay more than OCLD. The point is that this paper is rife with misleading items, and it is absolutely wrong to suggest that our criticism has to do with a "gotcha" on one insignificant item. As shown below in detail, we did not ignore the content of the primary academic studies at all. Taken as a group, they are fully consistent with our analyses, not with the claims of superior muni efficiency. As we stated in chapter 3, we reviewed all of them and sought to include only the minimum amount of such technical material as was necessary.

This error of commission is dwarfed by the crucial error of omission. ETAG either ignores or fails to give credence to modern day studies on the relative efficiency of public versus private power systems: studies that have been reviewed and accepted by academic institutions and journals.

Response: *This claim is simply a repeat of that in the previous paragraph. As we noted, we assumed no efficiency difference, contrary to what this criticism suggests -- even though much of the evidence supports an IOU efficiency margin, while the second largest group shows the "no difference" assumption we used, as discussed below.*

APPA has not conducted a full analysis of the ETAG study, and comments offered here address only the misuse of APPA-distributed materials. APPA urges the Public Utilities Commission to incorporate into its record and review of the ETAG study these APPA comments and the following primary source studies enclosed with this correspondence:

Response: *We have implemented this suggestion ourselves by revising the study to include more detail, as set forth here. When reviewed objectively, it does not say what APPA and some of its contractors claim it does.*

- William J. Hausman and John L. Neufeld, "*Public versus Private: A Summary of the Empirical Literature on the Comparative Performance of U.S. Electric Utilities*," prepared for the American Public Power Association, October, 1990.

Response: *Below is a list of the papers cited in this Hausman and Neufeld paper as either "The Recent Empirical Literature" or "Modern Analysis", not including those papers that do not address the question of IOU/muni efficiency. In particular, we highlight the conclusions of each paper as applied to electric distribution systems -- the issue here. On that basis, four of the studies support higher IOU efficiency, one supports higher muni efficiency, three show no difference, and five are not probative because they address electric generation, but not distribution. (Note in this regard: Hausman and Neufeld argued in their paper with some of the conclusions of the other papers, and sought to recast them, contrary to what the authors of those papers concluded about their own work. Hausman and Neufeld, APPA's consultants, did so while alleging bias by some other authors. Our account presents what the other authors themselves concluded, where that differs from the Hausman/Neufeld account, and we do not inject our own attempts to alter the conclusions, as they did.) We present them in the order Hausman and Neufeld did.*

- *Boardman & Vining, April 1989,* Journal of Law and Economics: *"Ownership and Performance in Competitive Environments: A Comparison of the Performance of Private, Mixed and State-Owned Enterprises" -- This survey, widely cited by everyone except Ventresca and APPA, shows many more studies concluded that private electric service is more efficient than public than the number that concluded to the contrary or found no difference.* ***Results favor IOUs.***
- *Peltzman, 1971* Journal of Law and Economics, *"Pricing in Public and Private Enterprises: Electric Utilities in the United States" -- Also widely cited, as Hausman and Neufeld admit while challenging its conclusions, private utilities are more efficient because publicly owned utilities mis-price service due to political pressure. Results favor IOUs.*

- *DeAlessi, 1974* Public Choice, *"An Economic Analysis of Government Ownership and Regulation: Theory and the Evidence from the Electric Power Industry"* -- *This survey concludes that private utilities are more efficient.* ***Results favor IOUs.***
- *DeAlessi, 1975* Economic Inquiry, *"Some Effects of Ownership on the Wholesale Prices of Electric Power"* -- *Although Hausman and Neufeld conclude that this article shows no difference, instead of an IOU advantage, the argument is mooted by the fact that this item addresses bulk-power supply, not distribution.* ***Results do not address distribution.***
- *Moore, April 1970* Southern Economic Journal, *"The Effectiveness of Regulation of Electric Utility Prices"* -- *In the words of Hausman and Neufeld, this statistical analysis which addressed residential electric rates, "found a significant difference in favor of privately owned firms."* ***Results favor IOUs.***
- *Yunker, Fall 1975* Journal of Economics and Business, *"Economic Performance of Public and Private Enterprises: The Case of U.S. Electric Utilities"* -- *As Hausman and Neufeld state, "the basic conclusion from this investigation would have to be that no significant ownership effects were found."* ***Results favor neither -- i.e., favor ETAG's usage.***
- *Meyer, November 1975* Review of Economics and Statistics, *"Publicly Owned versus Privately Owned Utilities: A Policy Choice"* -- *Again, in the words of Neufeld and Hausman, "no significant ownership differences for transmission and distribution costs." This is an item mis-classified by Ventresca in his 4-0 count, because he did not look at the results specific to distribution.* ***Results favor neither -- i.e., favor ETAG's usage.***
- *Neuberg, Spring 1977* Bell Journal of Economics, *"Two Issues in the Municipal Ownership of Electric Power Distribution Systems"* -- *This paper reports a 6% to 26% advantage for munis. ETAG's 6.4% base-case results in this study lie within this range; in fact, when the 55% of production and transmission costs are set aside, as Neuberg did, ETAG's base-case margin is 14.2%, which lies squarely in the mid-range of these results.* ***Results favor munis -- and they very much support ETAG's results.***
- *Pescatrice and Trapani, April 1980* Journal of Public Economics, *"The Performance and Objectives of Public and Private Utilities Operating in the United States"* -- *As Hausman and Neufeld state, "Data were gathered for the generation of electricity only."* ***Results do not address distribution.***
- *DiLorenzo and Robinson, Summer 1982* Quarterly Review of Economics and Business, *"Managerial Objectives Subject to Political Market Constraints: Electric Utilities in the U.S."* -- *This study considers generation costs only, and as Hausman and Neufeld state, "the dummy variable representing ownership was not significantly different from zero" -- meaning that statistically, this study showed no advantage to either side.* ***Results do not address distribution.***
- *Fare, Grosskopf and Logan, February 1985* Journal of Public Economics, *"The Relative Performance of Publicly-Owned and Privately-Owned Electric Utilities"* -- *This study also considers generation only, and finds, per Hausman and Neufeld, "No significant difference in overall efficiency."* ***Results do not address distribution.***
- *Atkinson and Halvorsen, April 1986* Journal of Public Economics, *"The Relative Efficiency of Public and Private Firms in a Regulated Environment: The Case of U.S.*

Electric Utilities" -- This study also addresses generation only and finds, per Hausman and Neufeld, "No significant differences in efficiency." ***Results do not address distribution.***

- *Hollas and Stansell, October 1988* Southern Economic Journal, *An Examination of the Net Effect of Ownership Form on Price Efficiency: Proprietary, Cooperative and Municipal Electric Utilities" -- Hausman and Neufeld begin their review of this item with: "This study used the most recent data and modern methodology to conclude that privately owned utilities were more efficient than were municipally owned utilities." It concludes, "Although flawed, the study by Hollas and Stansell was the only one to use data less than twenty years old." Unfortunately, it did not address distribution.* ***Results do not address distribution.***

- John E. Kwoka, Jr., *Ownership, Competition, and Price Performance of Electric Utilities*, Economics Discussion Paper D-9406, George Washington University, revised October 1994.

Response: *As noted above, this paper is derivative of and suffers from the same pervasive and disabling technical error as does the 1993 Kwoka paper. Thus, it can carry no evidentiary weight and its citation adds nothing here.*

- John E. Kwoka, Jr., *Public versus Private Ownership and Economic Performance: Evidence from the U.S. Electric Power Industry*, Discussion Paper 1712, Harvard Institute of Economic Research, Harvard University, February 1995.

Response: *As noted above, this paper is derivative of and suffers from the same pervasive and disabling technical error as does the 1993 Kwoka paper. Thus, it can carry no evidentiary weight and its citation adds nothing here.*

- MSB Energy Associates, *Explaining Public Power's Low Rates: A Critical Review of the EEI-Sponsored Report: "Subsidies and Unfair Competitive Advantages Available to Publicly Owned and Cooperative Utilities*," report to the American Public Power Association, April 5, 1996.

Response: *This paper is fundamentally wrong in its key attempts to refute another analysis. As an example, it makes incorrect adjustments to IOU deferred taxes, the ratemaking consequences of which were correctly recognized in the other study. The paper to which it responds showed a 4% IOU efficiency advantage -- but, again, we did not adopt such a position.*

These are important times and important decisions. Facts, as opposed to uninformed cliches or biases, about relative price and performance clearly support the advantages of public power. Good luck to San Francisco in its deliberations on whether or not to form a municipal electric utility.

Response: *Our quantitative analyses and assessments of non-quantifiable factors present the facts for the important decision here. Those criticizing it have relied on uninformed cliches and biases, but they have done nothing to show that any part of the analysis should be modified (although they have extensively misrepresented it, for example by suggesting that it assumed greater IOU than muni operating efficiency).*

Sincerely,

/s/
Deborah Penn
Assistant Executive Director,
Information Services

/s/
John Kelly
Director of Economics and Research

Enclosures

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MEMORANDUM

TO: SFPUC Commissioners via Messrs. Klein & Moran

FR: Ron Knecht & Ray Czahar, ETAG -6 February 1997 RK

RE: Changes Made to Our 31 December 1996 Draft of "Final Report: Feasibility Study ..."

1) In the Executive Summary (attached), a number of minor edits have been made throughout, including adding citations to other sections in response to Vice-President Makras's comments. In addition, the following changes have been made:

- In the middle of page ES-7, a new paragraph has been added to incorporate a number of items we provided in response to Vice-President Makras's questions. The main purpose of this information is to explain the quantitative results in terms that are more intuitive and understandable to the public and decision-makers.
- A new footnote (5) has been added at page ES-8, clarifying the differences between the contingency factors shown in Table ES-1 and systematic differences such as income-tax treatments and efficiency and other economy factors.
- Most of what was the first full paragraph on page ES-9 -- addressing the need for a follow-on, more extensive valuation study has been eliminated. In the paragraph that ends at the top of this page, we explain that, for purposes of the policy decision on whether to proceed with municipalization, the present study is sufficient. The more extensive valuation study should be viewed as the next or first step in a commitment to municipalization (and necessary if that path is elected), but in view of our findings it cannot add significant information that is needed for the policy decision.
- A new section heading has been added at page ES-10.

2) In section 3.B, the discussion of the academic and other literature on muni/IOU efficiency and performance has been expanded to include material from the answers we supplied in response to comments 47-53, especially item 51, by Joel Ventresca. This replaces the paragraph that spans pages 3-14 and 3-15, as well as the first paragraph of footnote 18 on page 3-14. Also in this section, the last paragraph on page 3-15 has been corrected to conform to the information on CPUC treatment

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of PG&E's senior-executive salaries as explained in our memo in response to Vice-President Makras's questions of 7 January 1997.

3) In response to Vice-President Makras's request for more citations throughout to the original source of information within our report, the following pages, besides the Executive Summary, include new citations: 1-2, 1-3, 1-5, 2-1, 2-5, 3-2, 3-4, 3-6, 4-4, 4-7 and 4-10. Other minor editorial improvements have been made on these pages and elsewhere in the text as necessary or appropriate on these pages and 2-2, 2-4, 2-22, 3-1, 3-3, 3-5, 3-6, 3-9, 3-10, 3-13, 4-9, 4-11, 4-29, 5-1, 5-2, 5-3, 5-10, 5-11, 5-12 and 5-17.

4) A glossary of acronyms has also been added to the main report.

EXECUTIVE SUMMARY

Introduction and Purpose

For 91 years, the Pacific Gas and Electric Company (PG&E) has provided electric utility service to customers in San Francisco (SF). In recent years, for various reasons, PG&E's electric rates have been among the highest in the United States. In over 2000 other communities, electric utility service is provided by a governmental agency, such as a city department or public power authority.[1] On average, as discussed in chapter 1 of this report, municipal (muni) electric rates are lower than those for investor-owned utilities (IOUs) such as PG&E.

On the other hand, despite wide knowledge of the munis' average cost advantage, there have not been any major muni or public-power-agency formations in recent decades. There were a number of them in the first half of the century. A number of large U.S. cities have studied electric-utility municipalization in recent years, especially in response to high rates such as those experienced in SF, but no major city is at present on the verge of municipalizing its electric service. A few smaller publicly-owned electric utilities have been formed in recent years, as discussed in chapter 1.

The City and County of San Francisco (CCSF or The City) has considered electric municipalization, reviewed studies of it, and held voter referenda on it at various times. With recent renewed interest in municipalization, The City's Public Utilities Commission hired the Economic & Technical Analysis Group (ETAG) to prepare this feasibility study of municipalizing the electric service in San Francisco. The project's purpose is mainly to determine the economics of a public-agency takeover of electric service in SF, versus continuing PG&E service (the "business as usual", or BAU, scenario here). Also, this study identifies processes and steps that will be involved if CCSF elects the muni option, as well as to assess risks, other possible costs and benefits to public concerns

[1]Figure from various recent documents, American Public Power Association (APPA).

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elects the muni option, as well as to assess risks, other possible costs and benefits to public concerns and major issues associated with this decision. CCSF recognizes that electric municipalization is a complex subject, and it desires to have a current assessment of the options and roadmap for the issue.

In particular, The City's Request for Qualifications -- Professional Services for this project states at page 1:

> "The major objective of this preliminary feasibility study is to determine, with some specificity, whether the potential benefits from municipalization are likely to outweigh the costs and the risks sufficiently to justify investment in a full feasibility study. The City understands that the preliminary feasibility study process may not yield an absolute, determinative finding that the City should or should not pursue municipalization. However, the City expects the consultant to reach a conclusion as to whether or not the City and its residents are likely to benefit from municipalization and, if so, by approximately how much.
>
> "The consultant should be prepared to conclude, and support its conclusion, that either:
> - o It is unlikely that the municipalization would result in any significant net savings to the businesses and residents of CCSF;
> - o Savings are more likely than not, but would be less than 5% compared to PG&E rates;
> - o Savings are likely and should be from 5% to 10% compared to PG&E rates;or
> - o Savings will almost certainly result and will likely exceed 10%."

Summary Results: Economics of Electric Municipalization in San Francisco

As discussed below, this study examines the costs that San Franciscans will pay to municipalize electric-utility services and the benefits they will receive, if they elect that option. One approach to this job is a simple total rates comparison, and we start with that approach. However, in studying the rates and benefits, it became clear that simple total rates comparisons misrepresent the true economic differences between muni and BAU alternatives. They distort the picture because they fail to account for the fact, explained in detail in chapter 4, that what the IOU ratepayer buys via paying a PG&E bill is different from what a muni ratepayer/owner gets for paying a muni's bill. Hence, after addressing the simple rates comparison, we turn to the larger economic comparison for a fuller picture.

Comparisons Based on Rates

On total electric rates, chapter 4 concludes that savings are more likely than not, but most probably they would be less than 5%, as compared to PG&E rates. Second most likely, but substantially less likely, we find, is that savings would be from 5% to 10%. Third most likely is that municipalization would not yield any savings, but would in fact increase electric rates by an amount less than 10%, compared to PG&E's rates. Finally, while it is not impossible, we find no evidence to support a change in SF electric rates from municipalization of more than 10%, whether up or down from PG&E's rates, and we believe such extreme outcomes are highly unlikely on both ends. The expected 30-year present-worth of savings (after purchasing the system and making normal annual capital expenditures) is $102-million, compared to a total bill of $3,315-million from PG&E service.

Three factors dominate rates comparisons for electric municipalization in SF: the price CCSF must pay to PG&E to acquire its SF electric-utility distribution system and related facilities; munis' exemption from federal and state income taxes (a close second); and avoidance by munis of the PG&E profit margin, as compared to muni interest rates (a distant third). The conclusion that rate economics is dominated by these three factors may sound obvious after the fact, but it was not clear at the outset, because the costs of SF muni electric service related to them are only slightly more than one-quarter of total muni electric costs (with the exact percentage depending on the acquisition cost).

As shown in chapter 4 and in the first two columns of Table ES-1 on page ES-5, in the future, well over half (about 55%, as compared to 65% presently) of the total cost of electric service in SF will be the cost of energy supply and transmission. We find this part will be the same for both muni and BAU options -- a result sought and achieved via the new regulatory and industry-structure framework passed into state law this summer, Assembly Bill (AB) 1890. Roughly 19% -- the costs to operate the distribution system, read meters, bill customers, etc. -- also will be about the same for the muni and BAU scenarios. Thus, because nearly three-quarters (about 74%) of the total costs (and rates) for electric service in SF will not be significantly affected by the municipalization decision, the remaining quarter (broken into three parts in the table), which is attributable to the acquisition cost, income taxes and PG&E equity return premium, dominates simple total rates comparisons.

This dependence of rates comparisons upon the acquisition cost is also a consequence of the great uncertainty over what that acquisition cost will be. The reason for the uncertainty is that the acquisition cost is determined in a legal process, called "condemnation", in which The City would seek a court order allowing it to take over PG&E's electric distribution facilities in SF and setting the compensation that it must pay to do so. The compensation would almost certainly be determined by a lay jury based on the testimony of expert witnesses, who would opine on the value to a utility such as PG&E of the property to be taken. Because there have been no comparable transactions (i.e., no takings of large local electric-utility systems) in several decades, there is no market in which to assess such a value, and it must be done by means other than market surveys (the law's preferred way).

Thus, the experts would present various theories and analyses (mainly "replacement costs" and "income valuations"), within certain limits as prescribed by the court, as to how the value should be determined and what it is. Reviewing these theories using the best available data in the analyses, and in view of the legal standards for such evidence, we conclude in chapter 2 that the jury would likely be confronted by a range of estimates from $500-million to at least $1-billion and quite possibly significantly higher. It is also possible, but quite uncertain, that a figure as low as $300-million could be put before the jury. In short, the range will be at least 100% above the lower value, and possibly well over 300% above it -- and this range of uncertainty will attend the kinds of numbers with which most jurors will almost certainly have no experience: hundreds of millions of dollars.

Complete Economic Analysis of the Muni and BAU Options

Table ES-1, on the next page, shows that, by shifting our focus from valuations and total rates comparisons to the components of the rates, we may see better the true economics of the choice between the muni and BAU options. Chapter 4's detailed examination of the components of the rates reveals that there are two components in the table on which the rate differences for the two scenarios are *apparent, but not real differences* (as also explained briefly below). One of these differences artificially favors municipalization and a larger one artificially opposes it. Thus, when the effects of these two components on the economic comparison are canceled by zeroing out these two rate-component differentials, as is done in the table, the comparison is more favorable to municipalization

than is suggested by the total-rates comparison. Section 4.A explains in detail these two items (reviewed briefly here below), two contingency items, and three related risk considerations.

The first item which is illusory in the CCSF rates column of the table is the "SF Distribution System Acquisition Valuation Premium". This percentage increase is simply the higher muni electric

Table ES-1: Economic Analysis of San Francisco's Electric-System Choice: Muni versus IOU/BAU (Cost Factors, Incorporating Restructuring Effects)

Cost/Rates Element	*PG&E Total Rates Component*	*CCSF Rates Changes Base/Low/High Cases*	*CCSF Real-Effect Economic Change*
Energy Supply, Including CTC & Transmission	55.3%	0.0%	0.0%
Distribution Operations, Customer Costs & Overhead	18.7%	-0.8%	-0.8%
PG&E Distribution Ownership Costs // CCSF Profit Elimination Savings	20.4%	-2.0%	0.0%
SF Distribution System Acquisition Valuation Premium	0.0%	+5.3% / -1.0% / +9.8%	0.0%
Federal & State Income Taxes	5.6%	-5.6%	-5.6%
Total	*100.0%*	*-3.1% / -9.4% / +1.4%*	*-6.4%*
Contingency Cases (See Chapter 4):			
CCSF Reliability, etc. "De-averaging"	0.0%	+3.0%	+3.0%
CCSF Avoids CTC "Tail"	0.0%	-1.0%	-1.0%
Total with Both Contingencies	100.0%	-1.1% / -7.4% / +3.4%	-4.4%

rate due to the extra amount CCSF would have to pay for PG&E's facilities, as compared to the depreciated book value assigned to them in setting PG&E's own rates. Because regulated and muni ratemaking is done on a cost-of-service basis, a higher valuation for the facilities means higher rates. However, what the PG&E and muni ratepayers purchase via their bills is quite different. The PG&E ratepayer is analogous to a renter of, say, a flat in San Francisco's Marina District -- while becoming a muni ratepayer/owner is analogous to becoming the owner of the flat. If a person lives in the flat, as either renter or owner, s/he will get the same service from it each month as s/he would in the other role. However, the owner has title to the future value of the property and the renter does not. The same is true for IOU ratepayers, as compared to muni ratepayer/owners.[2] Thus, muni electric ratepayer/owners, as a group, have a claim on the future value of their utility assets (in an era when industry restructuring may be increasing those assets' value) which IOU ratepayers do not have on their utility's assets. In the right-most column, reflecting the real economics of the muni/BAU choice, we have "zeroed-out" this differential, which previously opposed municipalization by adding 5.3% to its costs in the base case (and other amounts in the low- and high-cost cases).

The second *apparent, but not real difference* in this column is the "CCSF Profit Elimination Savings", which reflects the difference between PG&E's profit margin and muni-financing interest rates. When muni managers make imprudent or unreasonable (which does happen from time to time in nearly all enterprises), or when munis experience unfortunate contingencies, muni ratepayers must themselves carry the costs of those events, either through increased rates or taxes. On the other hand, when these things happen in regulated utilities, the principles of regulation promise to insulate ratepayers from them because they have been paying through their rates a profit to the IOU all along that compensates its stockholders for carrying such risks.[3] To continue the residential analogy, this

[2] After we developed this analysis, we learned that APPA also makes a similar but more limited point in its September 1996 publication, "The Value of a Public Power Distribution System: Increasing, *Not* Decreasing". Our perspective is that of economists: the point, in economic terms, is that the renter and owner are operating at different points on the same "indifference curve", not on different curves; hence, there is no net economic difference between their situations, contrary to what their rate differentials at first suggest. That is, each gets what s/he pays for, but one pays more and gets compensatively more in return (the claim on future value, in addition to present service).

[3] For example, the CPUC has disallowed recovery through rates of hundreds of millions of dollars of costs for nuclear plants owned by California electric utilities. Public-power ratepayers would have to pay such costs either in electric rates, in taxes, or in reduced public services; there would be no equity cushion to absorb such disallowances for them.

item is akin to carrying insurance on the contents of the flat in the Marina. IOU ratepayers pay a monthly insurance bill in paying a market rate of return on the IOU's investment, while muni ratepayer/owners self-insure and thus avoid the monthly premium by carrying the risk.[4] In this item, the IOU ratepayers have a claim on future value, which they realize when state IOU regulators disallow imprudent utility costs and which muni ratepayer/owners cannot reap due to their virtual owner roles. In the right-most column, reflecting the real economics of the muni/BAU choice, we "zeroed-out" this differential, which favored municipalization by reducing 2.0% from its costs.

To better convey the effect of municipalization, we note that the 5.6% income-tax savings (with a present worth of $186-million = $3,315-million x 5.6% and a first-year $19.9-million total) would reduce a typical $75 monthly residential bill by $4.20. The 1.96% profit-elimination savings would yield a reduction of $1.42, and the acquisition premium expected value of 5.3% would increase the bill by $3.98. By comparison, other items about which concern has been expressed are very small. As one example, senior-executive and other high-level salaries for PG&E electric service comprise about 0.1% of the total cost of service; thus, even if they could be wiped out with no off-setting costs for CCSF (which is not the case), the effect would be about six cents ($0.06) on that typical bill. On the other hand, lowering CCSF's interest rate for the take-over with tax-exempt bonds (which we do not believe is possible) would save 2.8% in a representative year (2007), or $2.11 on the typical bill.

In sum as a result of these two adjustments and related considerations in chapter 4, the true economic comparison between the two options should be restated as follows. Savings to San Franciscans are more likely than not, and we find that they would be between 5% and 10%, as compared to PG&E service. A close second most likely is that savings would lie in the 0% to 5% range. Third and fourth most likely -- both highly unlikely -- are that, respectively, municipalization would yield savings above 10% of the BAU costs to San Franciscans and that higher costs would result for San Franciscans from municipalization. Thus, on an economic basis, the expected present-value of 30-year cost savings exceeds $200-million, as compared to a total of $3,315-million -- again, after purchasing the system and paying all the normal upkeep, expansion and operating costs.

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[4]Again, from the economic viewpoint, the choice between these two positions is one of picking different locations on a given indifference curve -- i.e., they are equally "good" positions, even though the apparent price difference makes one look superficially more attractive than the other. Again, each ratepayer gets what s/he pays for, but one pays and gets more.

Thus, the real economic savings -- shown in the right-most column -- are almost completely due to a single factor: the avoidance of state and federal income taxes by munis, while IOUs must pay them and thus must be compensated for them in their regulated rates. This item favors the muni option by 5.6%. Another factor that adds a very small benefit, 0.8%, to municipalization for SF is that operating and maintenance costs for the SF electric distribution system are lower than the averages on PG&E's overall system, and San Franciscans would escape paying the differential (for IOU rates are based on system-average costs) by electing the muni option.[5] To decide whether municipalization is preferable to IOU ownership (BAU), these expected-value economic results -- i.e., expected net real economic savings of 6.4% -- must be weighed against the two electric-industry restructuring contingencies (shown at bottom of the table), and three other risk factors that attend the transition from IOU ownership to muni ownership. Those risk factors include acquisition-cost uncertainty (mis-valuation at trial), systematic efficiency differences (if any) between munis and monopoly-franchised/state-regulated IOUs, and net SF job losses due to PG&E possibly moving its corporate offices from SF in response to municipalization. We discuss all these items in chapter 4.

To sum up the salient facts: The initial cost is highly uncertain, probably (not certainly) lying between $500-million and $1-billion. Expected electric rates would be lower by 3%, although they would be higher in the early years and lower in later years. The expected net economic value, though, is a benefit equivalent to electric-bill reductions of 6%. However, both the rates and true economic effects are subject to uncertainties that could favor or oppose municipalization as they are realized.

Recommendation: If Proceeding, More Extensive Valuation Study Is Next

As a result of our analyses, we recommend that, if The City is inclined as a policy decision to pursue municipalization on the basis of these prospective costs, risks and benefits, and if it can spare the dollars from other pressing needs, it should next proceed to a more extensive valuation study.

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[5]Arguments can reasonably be made, as discussed in chapter 4, that this and other contingency factors shown in the table do not reflect the muni/IOU choice, but instead reflect state electric-industry pricing policies. The income-tax-based differences are systematic and inherent only to the muni/IOU choice. Economies of scope, scale and operating efficiency, as discussed in chapter 3, are also inherent to the muni/IOU choice, but due to SF's size and other operations, we have assumed that none of these factors will negatively affect the muni option, relative to the BAU scenario.

If such a study is undertaken, it should focus on the condemnation valuation, especially on the "replacement-cost" methods discussed in chapter 2. The foregoing analysis has shown that the rates comparison is dominated by three factors -- led by the acquisition-cost uncertainty, especially due to replacement-cost uncertainty. The true economic assessment, on the other hand, is dominated by the fact that the muni option avoids state and federal income taxes which IOUs must pay and which they pass on to their ratepayers (a factor that is virtually certain for the foreseeable future). While clearing up uncertainty about condemnation valuation has a major effect on rates, it plays only a minor role in the true risk-adjusted economics. The present study is sufficient as a basis to understand the complete economics of the choice between the two options, and to make a policy decision, and the more detailed valuation study is not, in our view, needed for that purpose.

One could argue that an extended valuation study is merited because the expected benefit from municipalization is high enough -- even at the modest levels, relative to PG&E's rates, that this study finds -- to justify the roughly $1-million cost of the extended valuation study. On the other hand, this expected benefit must be weighed against the likelihood that, mainly as a consequence of undertaking the study, municipalization will proceed. From this view, if the present study is sufficient, as we believe it is, to make the policy decision, then the extended study is needed only if the policy decision is to pursue municipalization. (Under the terms of the contract for this project, ETAG may not be a candidate to do this follow-on work.)

As discussed in section 5.A, our investigations have also turned up a potential legal trip-wire for municipalization that may be avoided by an abundance of caution in proceeding and a strong showing on the benefits, if net benefits they prove to be, for the muni option. An extended valuation study may help avoid that trip-wire, or it may be counter-productive, depending on its outcome. The legal problem is that a 1992 provision added to state law applying to municipalizations now makes the condemnation trial court (i.e., the trial judge) the authority who must ultimately rule on whether The City has made an adequate showing that municipalization is in the public interest, all factors considered. Before this provision was added, the determination of the CCSF's Board of Supervisors would have been final on this matter, as long as the Board had some reasonable basis for a finding of what is called, in the law, "public necessity". As a result of this provision, before the condemnation

case can proceed jury selection and trial on the valuation, PG&E will have a full opportunity to try to persuade the court, via a most-likely extensive factual showing (essentially, a bench trial before the jury trial) that municipalization is not in the public interest or "necessity" and that it is an inferior option, considering the full range of public policy concerns and private losses and risks at stake. While an extended valuation study will not be fully dispositive on this issue in any event, it may help resolve the uncertainty, and it will very likely be required if The City proceeds with municipalization.

Overview and Roadmap for the Report

Our study incorporates the effects of recent changes at the state and federal levels in electric regulation and industry organization, assuring that it is current and useful for policy and planning. It thoroughly reviews municipalization success factors, obstacles and recurring problems. While it cannot provide the ultimately precise original- and replacement-cost estimates, it is definitive on the other valuation issues, including the role of valuation for the municipalization policy decision for SF. It is also definitive on the rates and economic comparisons for the muni/IOU choice, as well as for assessment of the other (non-valuation) factors in those comparisons and the specification and role of non-quantifiable factors in the decision. This study also compares our results with previous studies and extensively reviews comparative muni/IOU experience nationally and in California. It presents a process map, time table and rough budget for the road to municipalization, if it is chosen, and it reviews its legal and financial issues, other risks, and alternatives and environmental impacts.

The road-map for this study is as follows. Chapter 1 presents a survey of the experience of other electric munis and municipalization efforts to provide insight and guidance for the study. Chapter 2 addresses acquisition valuation issues, and chapter 3 handles all other cost factors. Chapter 4 pulls together all factors to produce a comprehensive economic analysis. These three chapters constitute the core of this feasibility and cost/benefit study. Finally, chapter 5 addresses procedure, time table and other matters, while chapter 6 shows how we have fully incorporated the effects of electric-industry restructuring. Each chapter begins with a 3-10 page introduction and summary, followed by the substantive analysis in the body of the chapter. A separate volume includes workpapers and responses to formal comments on the report drafts.

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MEMORANDUM

TO: SFPUC Commissioners via Messrs. Klein & Moran

FR: Ron Knecht & Ray Czahar, ETAG - 10 February 1997 RK

RE: Minor Correction to Our 31 December 1996 Draft of "Final Report: Feasibility Study"

In further checking our numbers, we found a minor error in allocation of the rates savings among factors. By its nature, this error increases both the equity premium and the acquisition premium percentages by the same amount. Thus, because they have opposite effects (i.e., offset each other), correcting this error makes no difference to the bottom line of either the rates savings or the economic comparison of the muni and business-as-usual options. For this reason, it was not discovered earlier when those key bottom-line numbers were checked.

The attached Table ES-1 includes the corrections in the middle column of numbers, as well as correction of a related rounding error (from 1.4% to 1.3%), and for publication of the final report, we will also correct the numbers in the text taken from this table. In chapter 4, we will modify tables 4-4 through 4-7 and add a table 4-8 to show explicitly the computation of these factor allocations.

than is suggested by the total-rates comparison. Section 4.A explains in detail these two items (reviewed briefly here below), two contingency items, and three related risk considerations.

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Total	*100.0%*	*-3.1% / -9.4% / +1.3%*	*-6.4%*
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